2014 State of the Market Report for PJM

March 26, 2015

MC Special Session

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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

Role of Market Monitoring

- **Detailed monitoring required:**
  - **Of participants**
  - **Of RTO**
  - **Of rules**
- **Market monitoring is primarily analytical**
  - **Adequacy of market rules**
  - **Compliance with market rules**
  - **Exercise of market power**
  - **Market manipulation**

Role of Market Monitoring

- **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.
- Monitor for market manipulation.

Figure 1-1 PJM's footprint and its 20 control zones

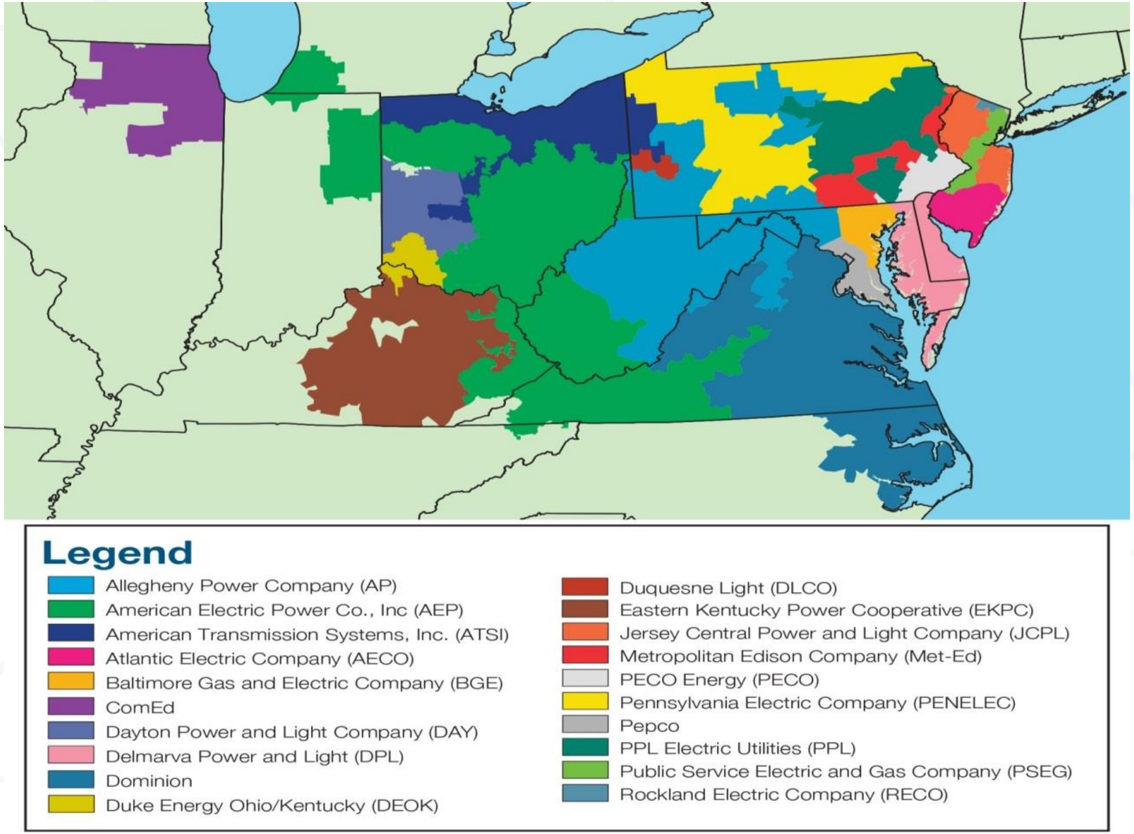

Table 3-1 The Energy Market results were competitive

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**
  - **PJM should routinely review all transmission facility ratings**
  - **Permit cost-based offers above the $1,000/MWh energy offer cap excluding the ten percent adder, subject to after the fact review by the MMU.**

Table 1-9 Total price per MWh by category: 2013 and 2014

Category	2013 $/MWh	2014 $/MWh	Q1 2014 $/MWh	Q2 2014 $/MWh	Q3 2014 $/MWh	Q4 2014 $/MWh	2013 to 2014 Percent Change Totals	2013 Percent of Total	2014 Percent of Total
Load Weighted Energy	$38.66	$53.14	$92.98	$42.85	$36.38	$35.47	37.4%	71.6%	74.2%
Capacity	$7.13	$9.01	$7.77	$9.48	$9.16	$14.11	26.3%	13.2%	12.6%
Transmission Service Charges	$5.20	$5.95	$5.19	$6.22	$6.05	$9.31	14.5%	9.6%	8.3%
Energy Uplift (Operating Reserves)	$0.59	$1.18	$3.55	$0.34	$0.27	$0.41	99.4%	1.1%	1.6%
Transmission Enhancement Cost Recovery	$0.39	$0.42	$0.36	$0.86	$1.22	$2.55	8.9%	0.7%	0.6%
PJM Administrative Fees	$0.43	$0.44	$0.43	$0.47	$0.45	$0.59	1.5%	0.8%	0.6%
Reactive	$0.80	$0.40	$0.37	$0.47	$0.38	$0.55	(50.4%)	1.5%	0.6%
Regulation	$0.24	$0.33	$0.63	$0.26	$0.18	$0.29	33.1%	0.5%	0.5%
Synchronized Reserves	$0.04	$0.21	$0.56	$0.12	$0.03	$0.10	382.5%	0.1%	0.3%
Capacity (FRR)	$0.11	$0.20	$0.06	$0.16	$0.30	$0.46	90.2%	0.2%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.09	$0.09	$0.09	$0.09	$0.13	7.4%	0.2%	0.1%
Black Start	$0.14	$0.08	$0.06	$0.07	$0.10	$0.11	(45.9%)	0.3%	0.1%
Emergency Load Response	$0.06	$0.06	$0.18	$0.03	$0.00	$0.00	(14.9%)	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.06	$0.05	$0.17	$0.00	$0.00	$0.00	(19.5%)	0.1%	0.1%
NERC/RFC	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	5.6%	0.0%	0.0%
Load Response	$0.01	$0.02	$0.04	$0.02	$0.01	$0.02	69.8%	0.0%	0.0%
Non-Synchronized Reserves	$0.00	$0.02	$0.04	$0.01	$0.00	$0.01	625.0%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	(11.9%)	0.0%	0.0%
Emergency Energy	$0.00	$0.01	$0.13	$0.00	$0.00	$0.00	NA	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	(8.7%)	0.0%	0.0%
Total	$54.00	$71.62	$112.62	$61.48	$54.64	$64.15	32.6%	100.0%	100.0%

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2013 and 2014

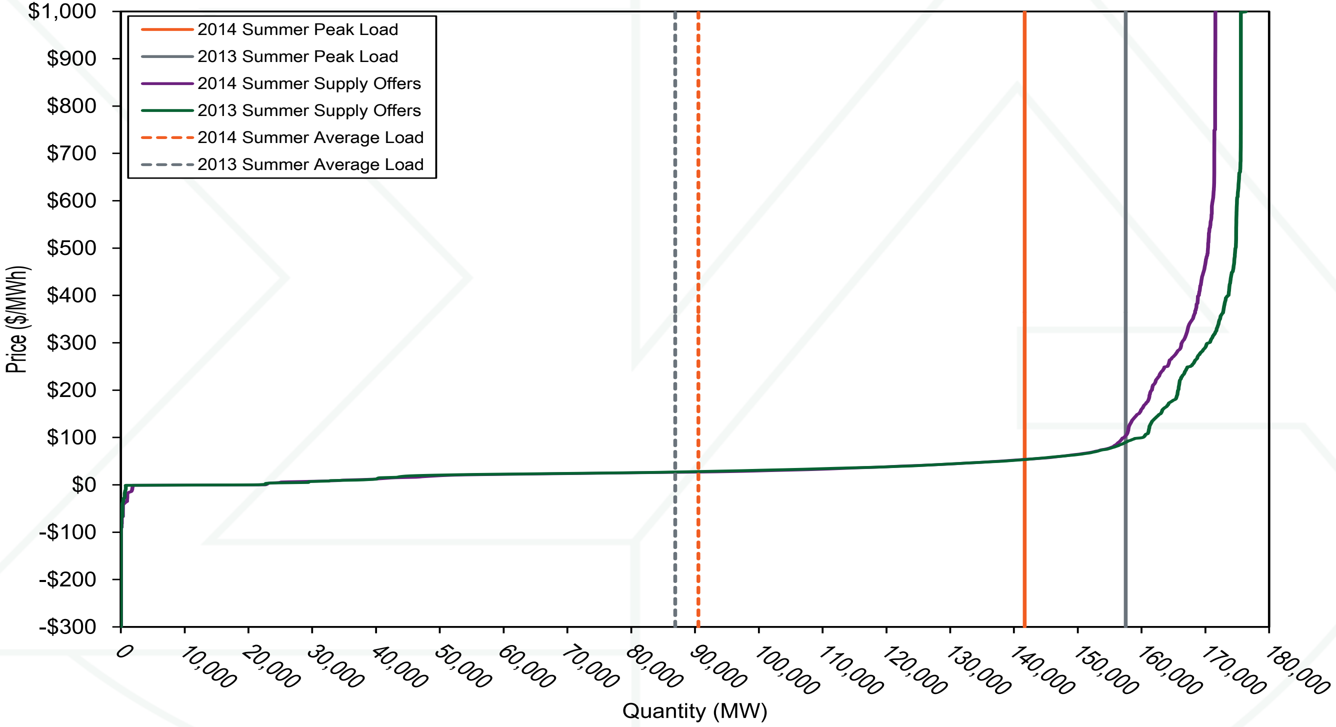

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2014

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
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%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%

Figure 3-15 PJM real-time monthly average hourly load: 2013 and 2014

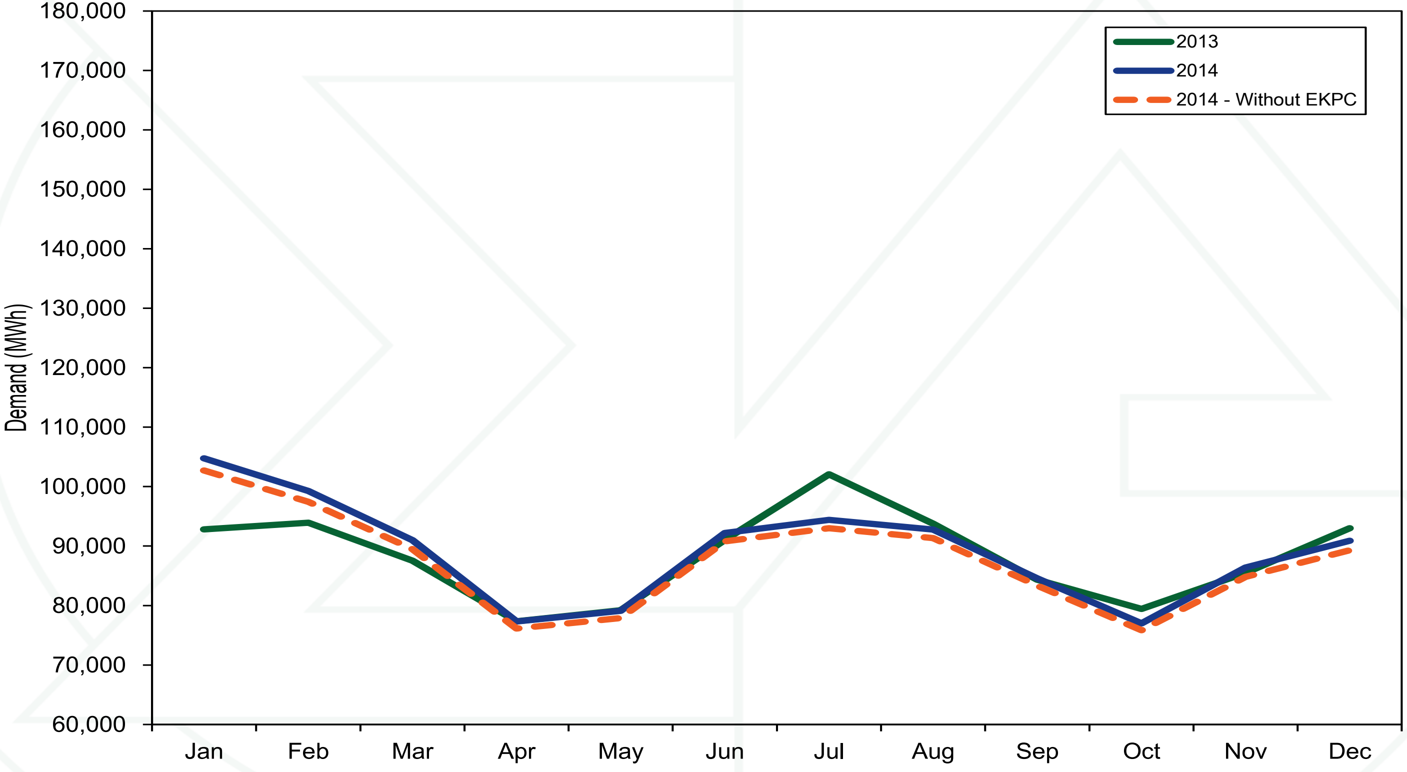

Table 3-62 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2014

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	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%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%

Figure 3-30 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2014

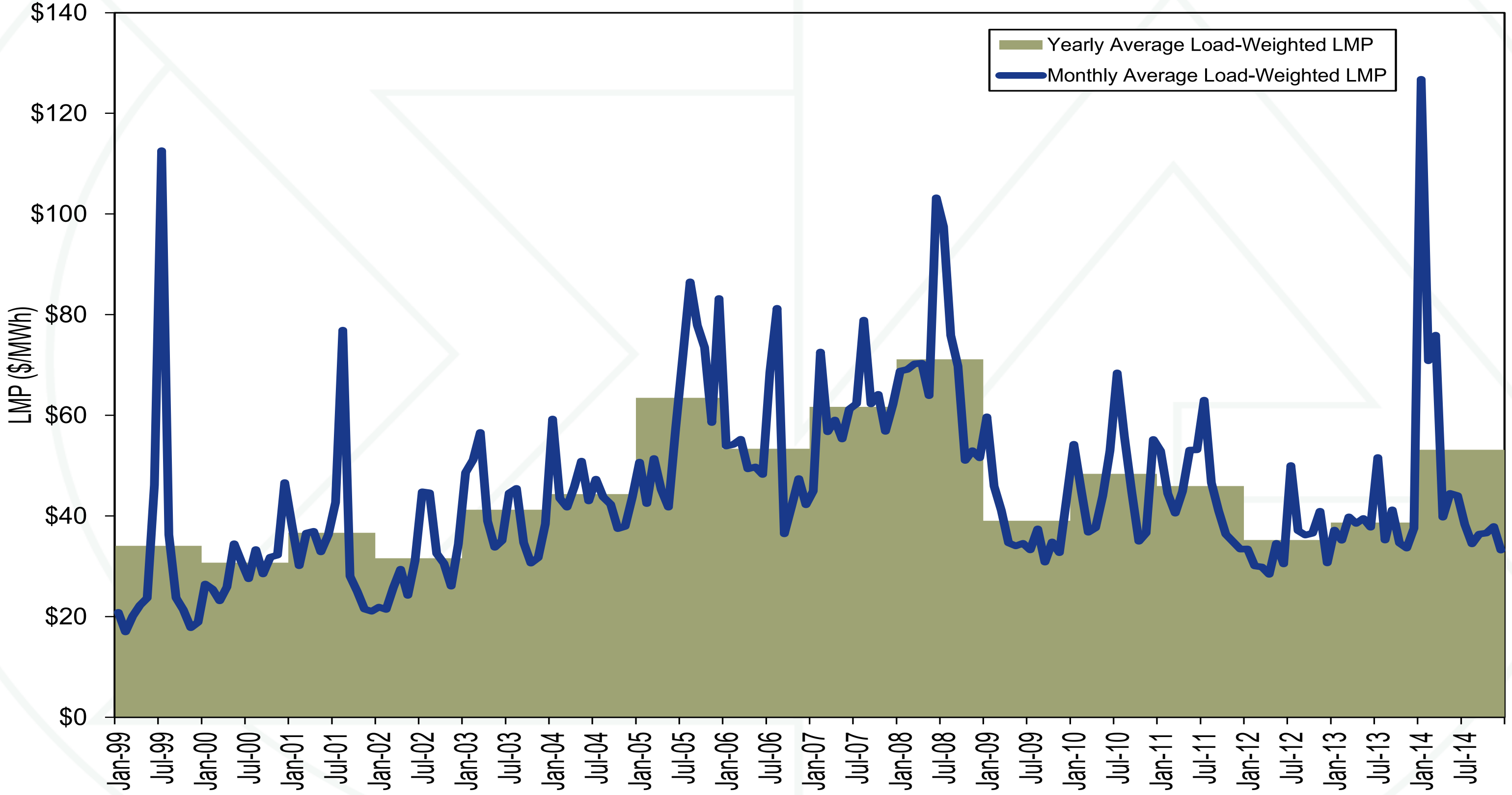

Figure 3-31 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)

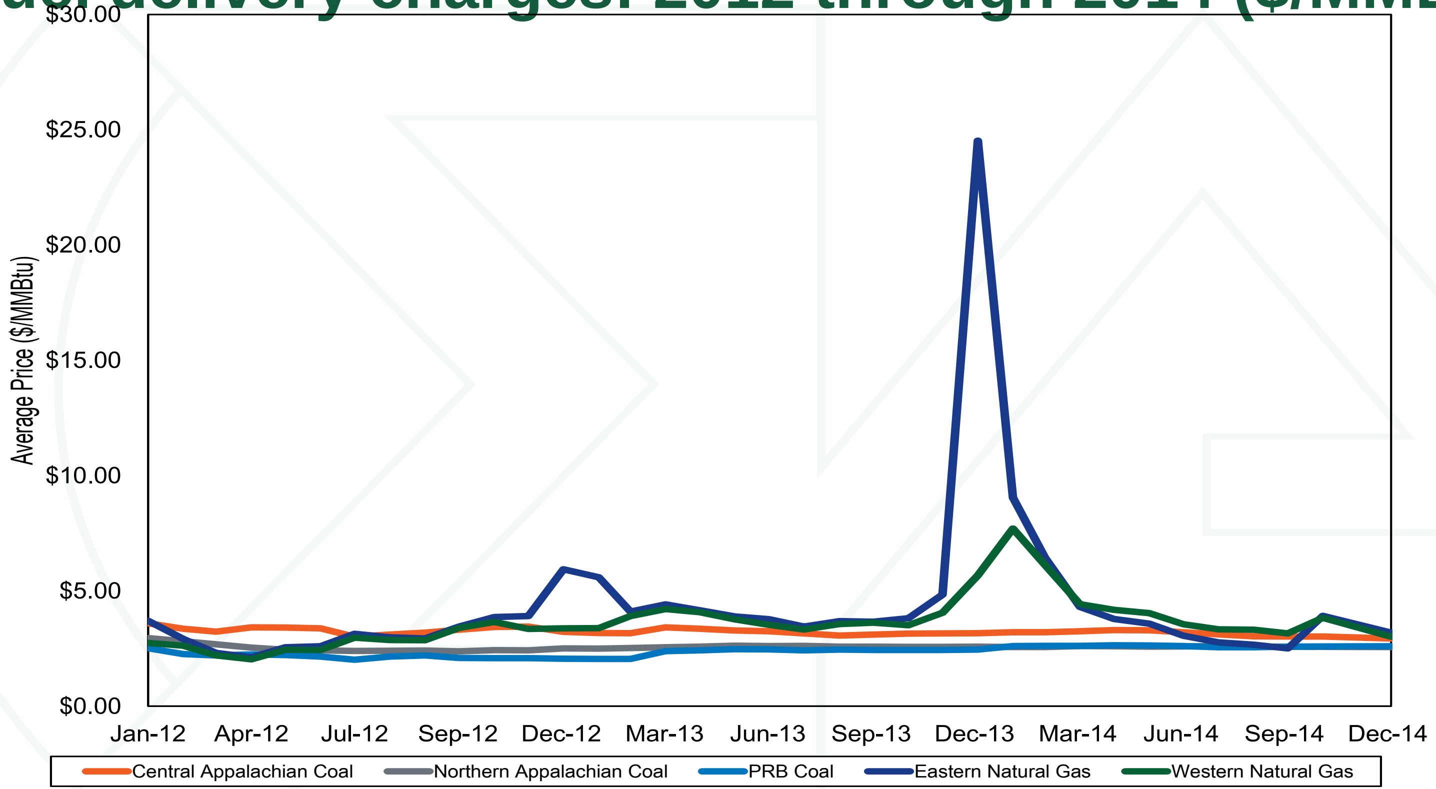

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Figure 7-2 Average operating costs: 2009 through 2014

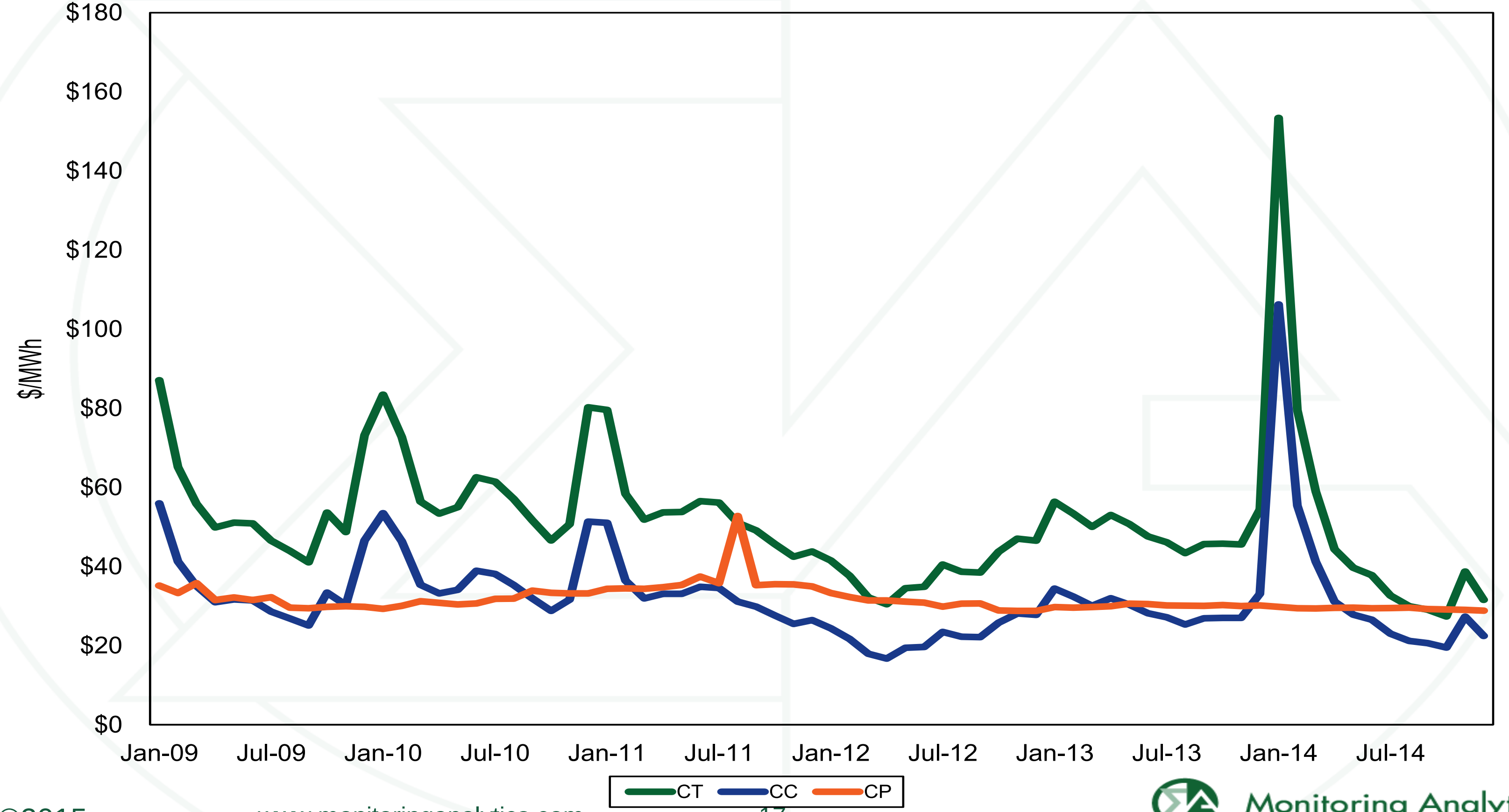

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Table 3-64 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): year over year

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.14	$47.43	(10.7%)

	2013 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$38.66	$47.43	22.7%

	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$38.66	$53.14	37.4%

Table 3-8 PJM generation (By fuel source (GWh)): 2013 and 2014

		2013		2014		
		Gwh	Percent	GWh	Percent	Change in Output
Coal		356,018.0	44.5%	351,456.5	43.5%	(1.3%)
	Standard Coal	346,188.8	43.3%	341,538.6	42.3%	(1.3%)
	Waste Coal	9,829.2	1.2%	9,918.0	1.2%	0.9%
Nuclear		277,277.8	34.7%	277,635.6	34.3%	0.1%
Gas		130,230.9	16.3%	140,076.4	17.3%	7.6%
	Natural Gas	127,855.5	16.0%	137,503.6	17.0%	7.5%
	Landfill Gas	2,321.0	0.3%	2,369.4	0.3%	2.1%
	Biomass Gas	54.5	0.0%	203.5	0.0%	273.3%
Hydroelectric		14,116.4	1.8%	14,394.3	1.8%	2.0%
	Pumped Storage	6,690.4	0.8%	7,138.7	0.9%	6.7%
	Run of River	7,426.0	0.9%	7,255.5	0.9%	(2.3%)
Wind		14,854.1	1.9%	15,540.5	1.9%	4.6%
Waste		5,040.1	0.6%	5,472.4	0.7%	8.6%
	Solid Waste	4,185.0	0.5%	4,566.5	0.6%	9.1%
	Miscellaneous	855.1	0.1%	905.9	0.1%	5.9%
Oil		1,948.5	0.2%	3,299.9	0.4%	69.4%
	Heavy Oil	1,730.7	0.2%	2,742.1	0.3%	58.4%
	Light Oil	187.2	0.0%	480.0	0.1%	156.5%
	Diesel	14.8	0.0%	52.5	0.0%	253.6%
	Kerosene	15.7	0.0%	25.3	0.0%	61.3%
	Jet Oil	0.1	0.0%	0.1	0.0%	(38.6%)
Solar, Net Energy Metering		355.0	0.0%	404.6	0.0%	13.7%
Battery		0.7	0.0%	6.5	0.0%	807.7%
Total		799,841.7	100.0%	808,286.8	100.0%	1.1%

Table 3-21 Offer-capping statistics – Energy only: 2010 to 2014

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2014	0.5%	0.2%	0.2%	0.1%

Table 3-67 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2013 and 2014

Element	2013 Contribution to LMP	2013 Percent	2014 Contribution to LMP	2014 Percent	Change Percent
Gas	$11.56	29.9%	$18.71	35.2%	5.3%
Coal	$18.91	48.9%	$17.73	33.4%	(15.5%)
Markup	$1.16	3.0%	$3.32	6.2%	3.2%
Oil	$0.83	2.1%	$2.80	5.3%	3.1%
VOM	$2.36	6.1%	$2.65	5.0%	(1.1%)
Ten Percent Adder	$1.70	4.4%	$2.33	4.4%	(0.0%)
Emergency DR Adder	($0.21)	(0.5%)	$1.83	3.4%	4.0%
NA	$1.06	2.7%	$1.56	2.9%	0.2%
Increase Generation Adder	$0.15	0.4%	$0.69	1.3%	0.9%
FMU Adder	$0.55	1.4%	$0.62	1.2%	(0.2%)
Ancillary Service Redispatch Cost	$0.19	0.5%	$0.52	1.0%	0.5%
CO2 Cost	$0.12	0.3%	$0.23	0.4%	0.1%
NOx Cost	$0.10	0.3%	$0.13	0.2%	(0.0%)
Scarcity Adder	$0.00	0.0%	$0.10	0.2%	0.2%
LPA Rounding Difference	$0.53	1.4%	$0.07	0.1%	(1.2%)
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.20)	(0.5%)	($0.01)	(0.0%)	0.5%
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.15)	(0.4%)	($0.17)	(0.3%)	0.1%
Total	$38.66	100.0%	$53.14	100.0%	0.0%

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Table 11-8 Total PJM congestion (Dollars (Millions)): 2008 to 2014

	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%
2014	$1,932.2	185.5%	$50,030	3.9%

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 to 2014

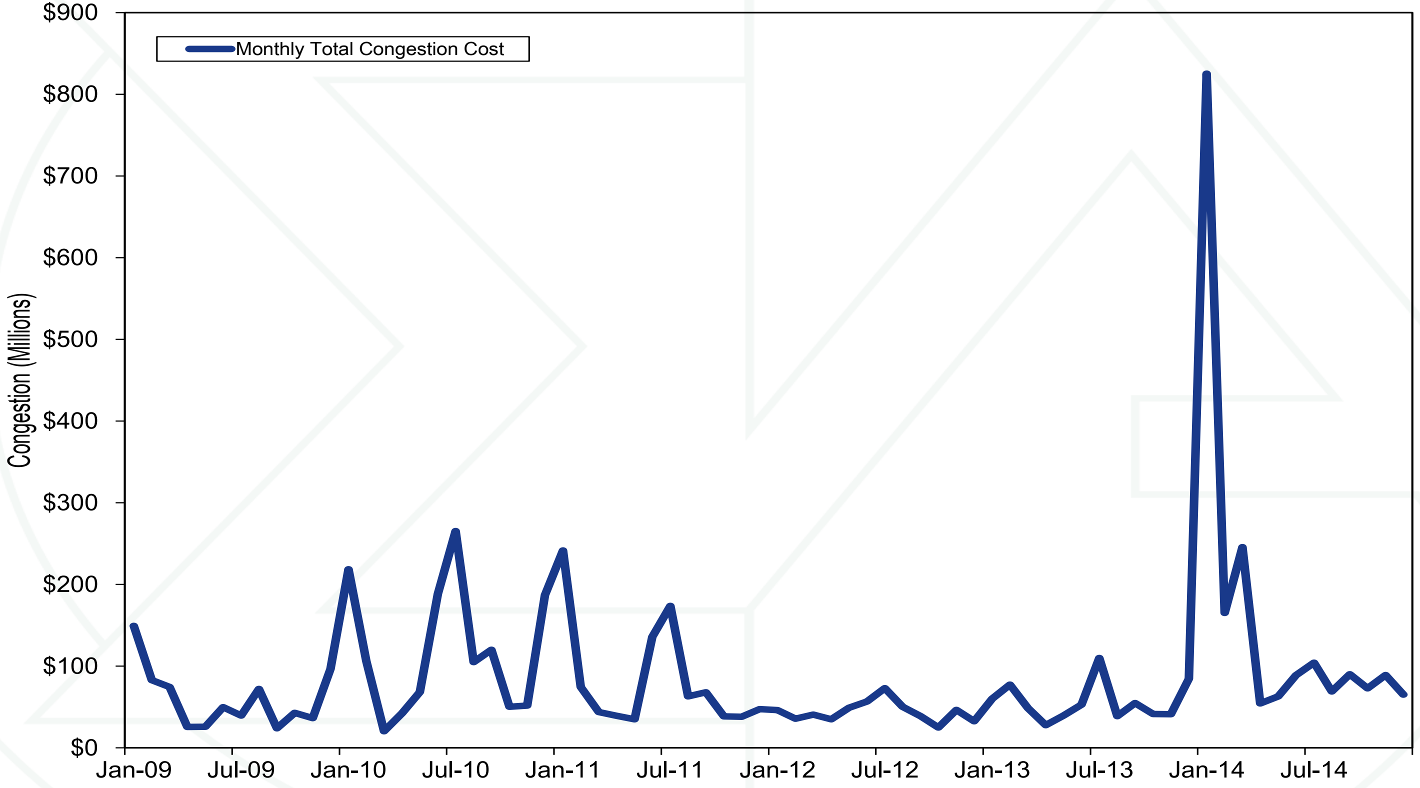

Table 5-1 The Capacity Market results were competitive

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, 2014

	1-Jan-14		31-May-14		1-Jun-14		31-Dec-14	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,544.6	41.3%	75,253.0	41.1%	74,785.5	40.6%	73,015.3	39.7%
Gas	53,395.0	29.2%	53,841.6	29.4%	55,041.7	29.9%	56,364.5	30.7%
Hydroelectric	8,106.7	4.4%	8,135.7	4.4%	8,463.8	4.6%	8,765.3	4.8%
Nuclear	33,076.7	18.1%	33,073.7	18.0%	32,891.0	17.9%	32,947.1	17.9%
Oil	11,314.2	6.2%	11,290.4	6.2%	11,155.7	6.1%	10,931.7	6.0%
Solar	84.2	0.0%	84.2	0.0%	94.7	0.1%	97.5	0.1%
Solid waste	701.4	0.4%	701.4	0.4%	780.0	0.4%	780.0	0.4%
Wind	872.4	0.5%	872.4	0.5%	796.7	0.4%	822.7	0.4%
Total	183,095.2	100.0%	183,252.4	100.0%	184,009.1	100.0%	183,724.1	100.0%

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2014

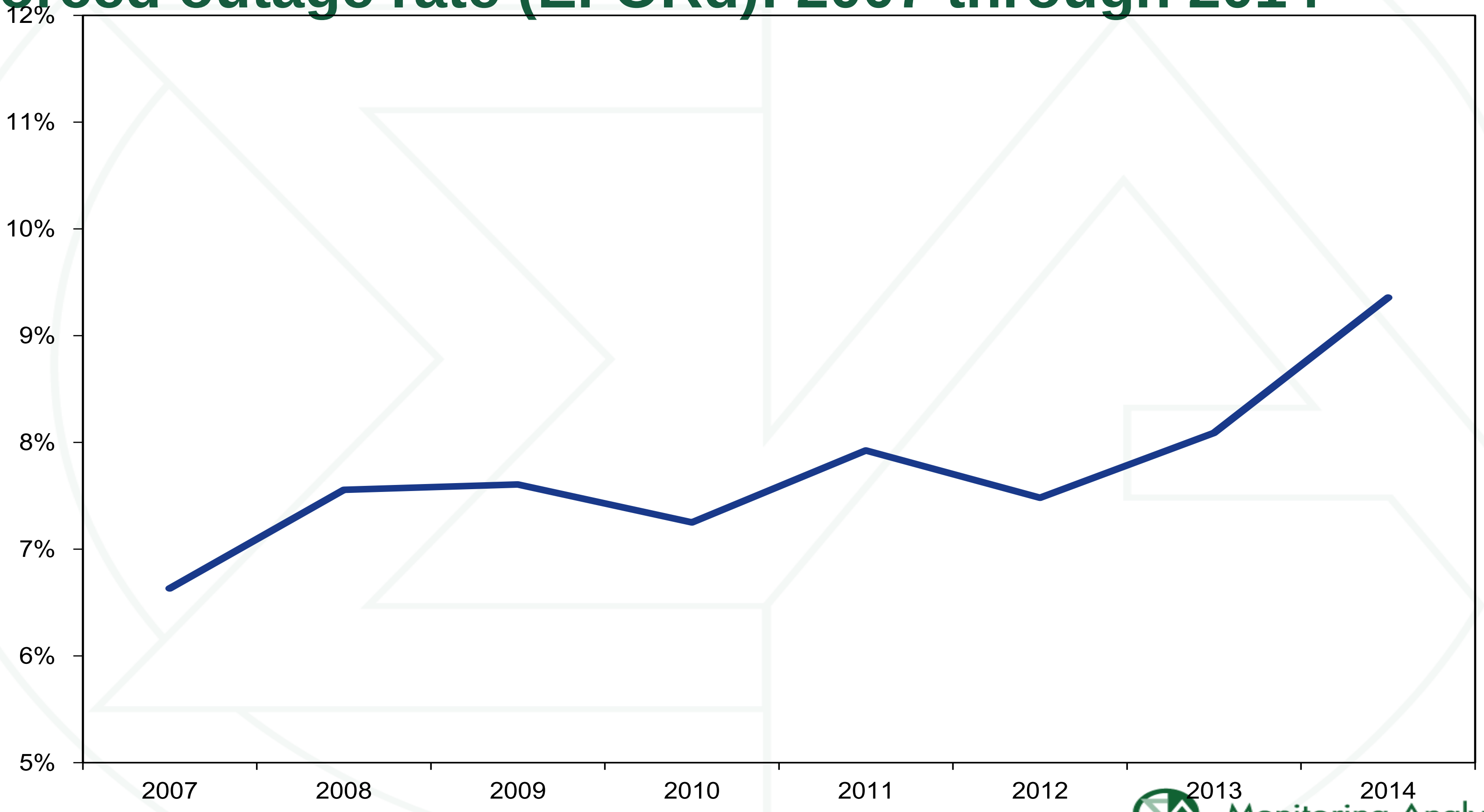

Table 5-34 PJM EFORd, XEFORd and EFORp data by unit type

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	4.3%	4.1%	2.8%	0.2%	1.5%
Combustion Turbine	15.6%	13.1%	12.2%	2.5%	3.4%
Diesel	14.8%	14.6%	5.4%	0.2%	9.4%
Hydroelectric	3.8%	2.5%	1.3%	1.2%	2.5%
Nuclear	1.9%	1.9%	2.7%	0.1%	(0.8%)
Steam	12.1%	11.9%	10.1%	0.1%	2.0%
Total	9.4%	8.8%	7.7%	0.6%	1.6%

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

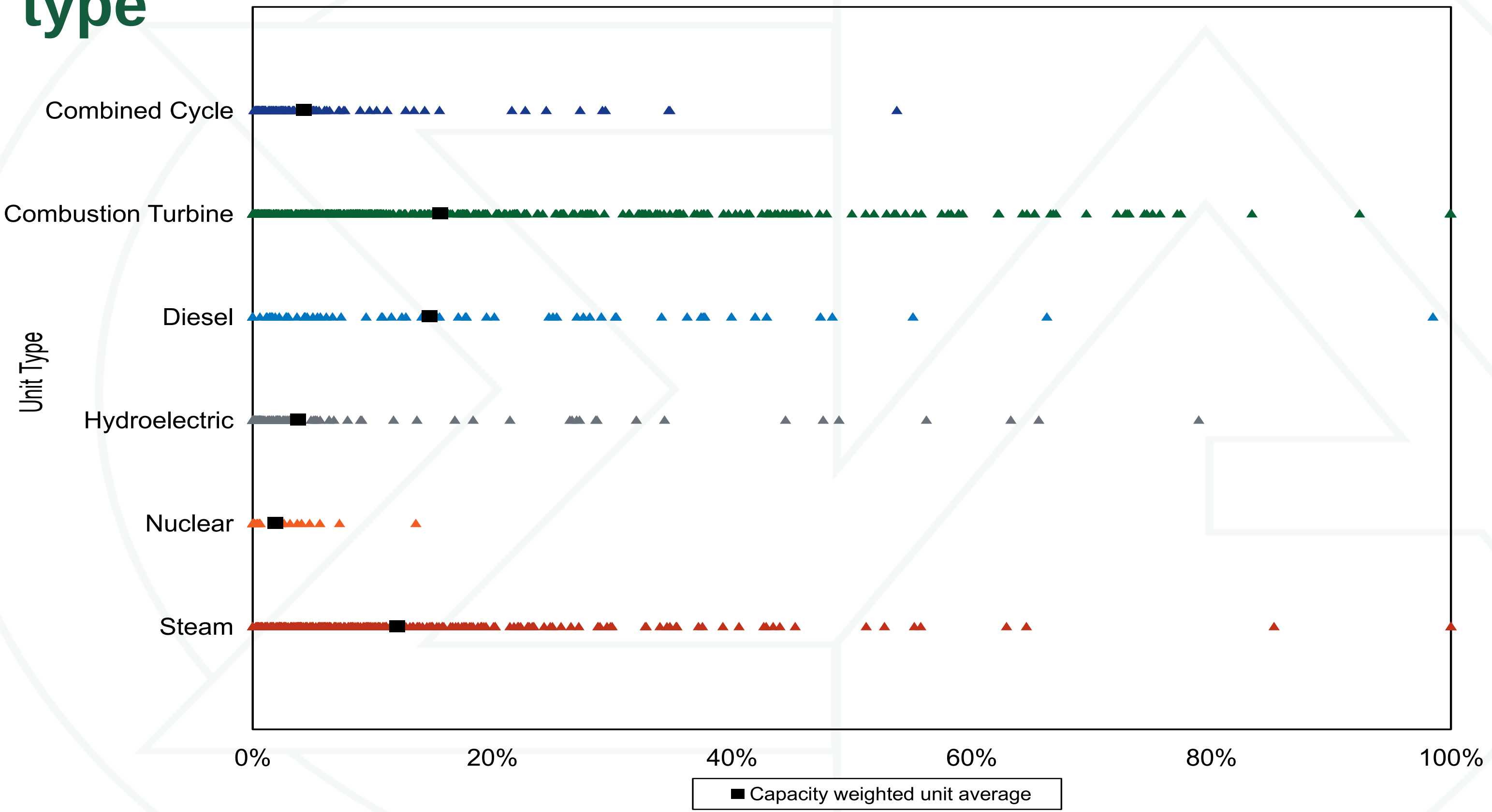

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Figure 5-4 History of PJM capacity prices: 1999/2000 through 2017/2018

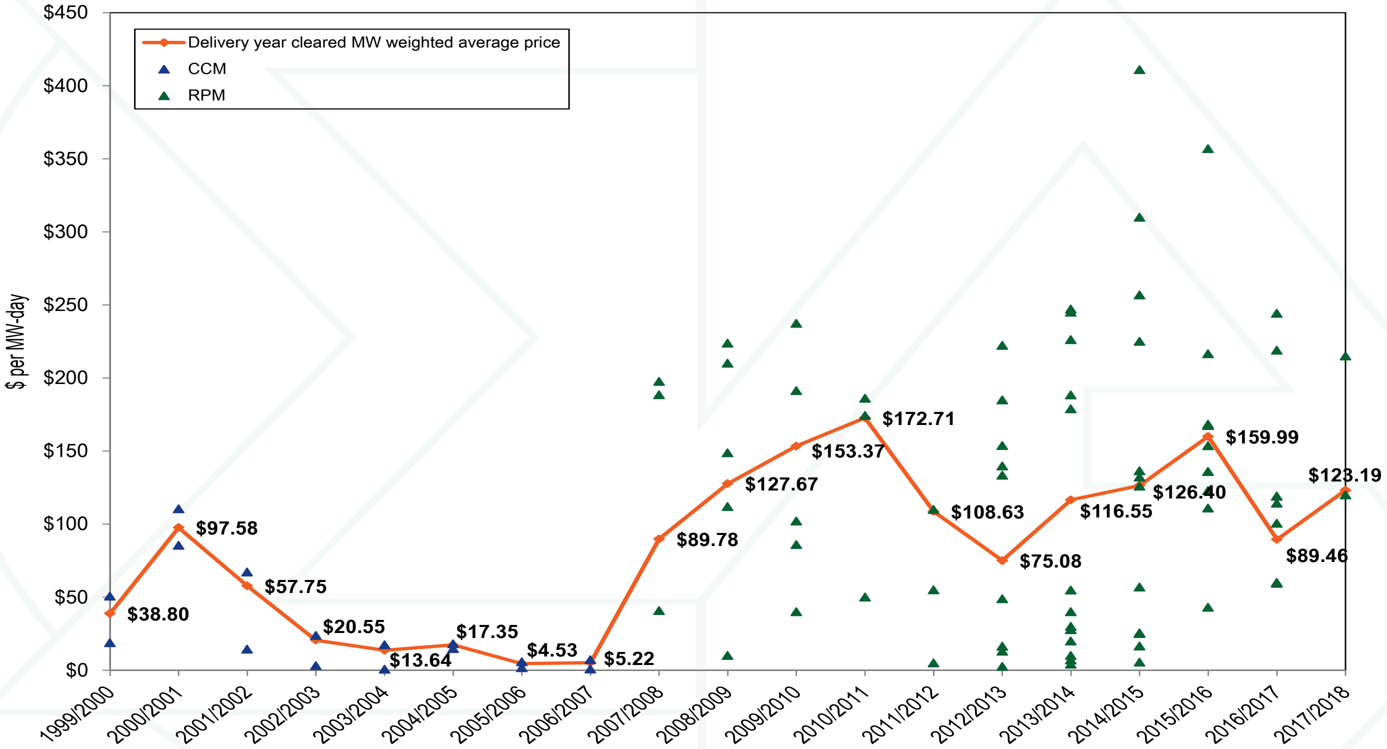


Figure 7-3 New entrant CT net revenue and 20-year levelized total cost by LDA

Figure 7-4 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year)

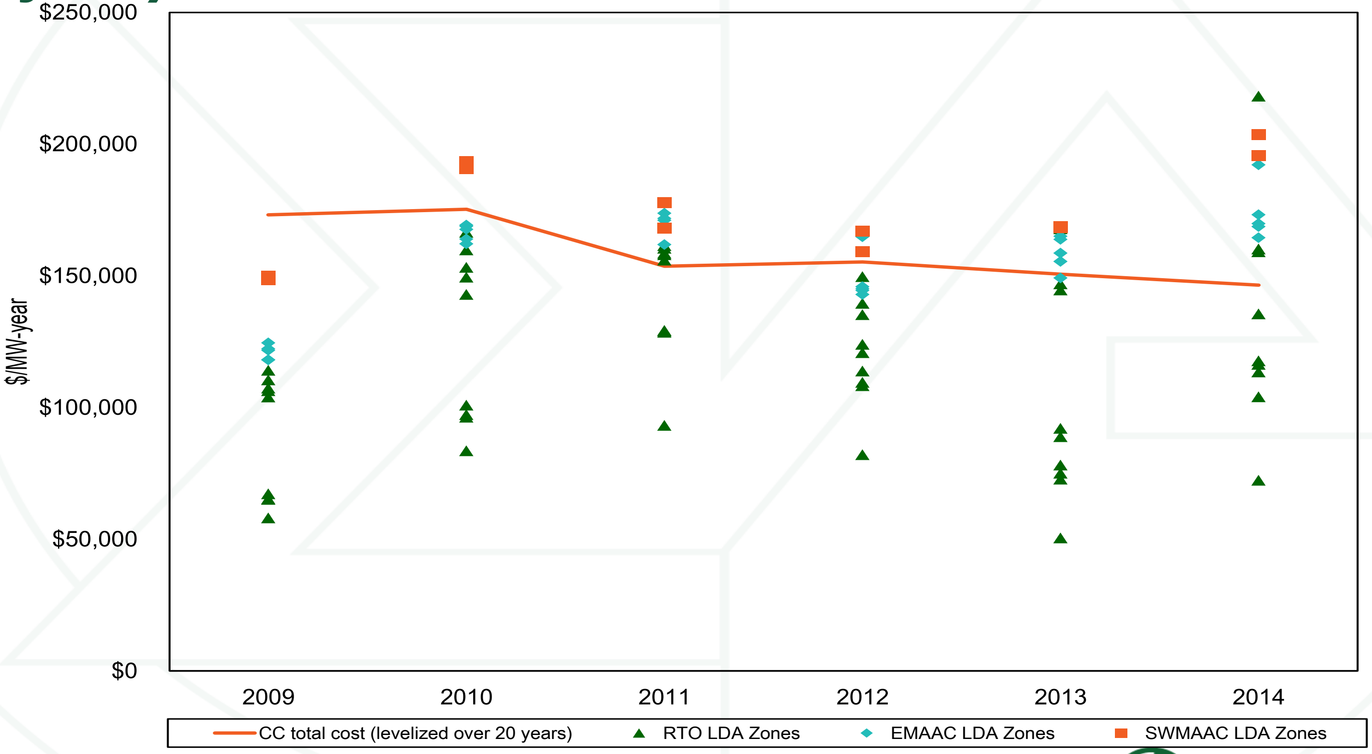


Figure 7-5 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year)

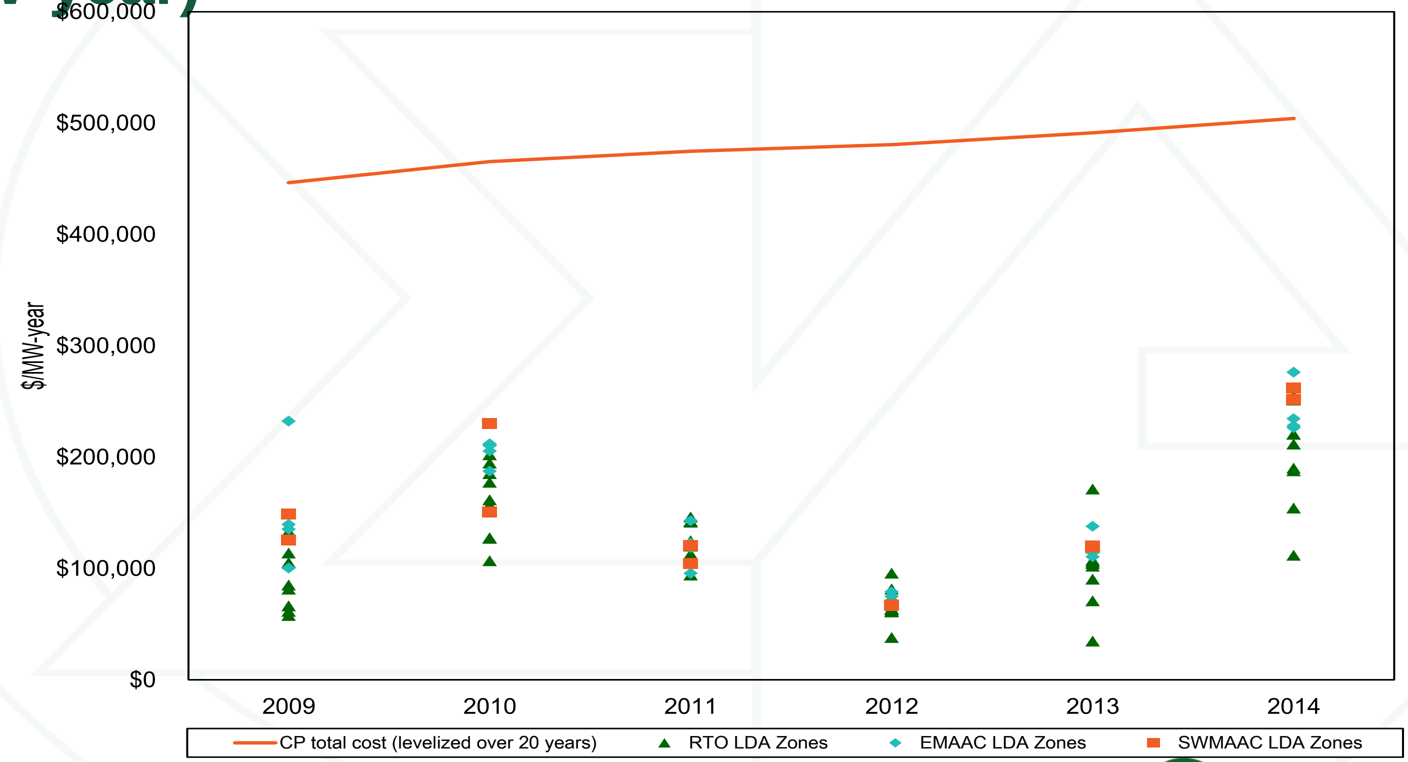


Table 7-19 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue

Zone	2009	2010	2011	2012	2013	2014
AECO	43%	54%	49%	34%	42%	52%
AEP	32%	39%	39%	28%	30%	39%
AP	39%	47%	43%	29%	32%	42%
ATSI	NA	NA	NA	NA	NA	41%
BGE	47%	57%	50%	36%	44%	58%
ComEd	27%	33%	33%	25%	27%	35%
DAY	31%	38%	39%	28%	31%	40%
DEOK	NA	NA	NA	NA	29%	38%
DLCO	31%	38%	39%	28%	30%	37%
Dominion	40%	53%	47%	31%	34%	48%
DPL	44%	54%	49%	36%	43%	56%
EKPC	NA	NA	NA	NA	NA	37%
JCPL	43%	53%	48%	34%	43%	52%
Met-Ed	42%	52%	47%	33%	40%	50%
PECO	43%	53%	48%	33%	41%	51%
PENELEC	38%	46%	43%	33%	40%	47%
Pepco	47%	57%	48%	35%	44%	56%
PPL	41%	51%	46%	32%	40%	50%
PSEG	44%	54%	49%	35%	45%	56%
RECO	NA	NA	NA	NA	NA	NA
PJM	39%	49%	44%	31%	36%	47%

Table 7-21 Percent of 20-year levelized total costs recovered by wind energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014
ComEd	65%	75%	91%
PENELEC	68%	83%	103%

Table 7-23 Percent of 20-year levelized total costs recovered by solar energy and capacity net revenue (Dollars per installed MW-year)

Zone	2012	2013	2014
PSEG	97%	203%	244%

Table 7-35 Avoidable cost recovery from all markets net revenues

	Units with full recovery from all markets					
Technology	2009	2010	2011	2012	2013	2014
CC - NUG Cogeneration Frame B or E Technology	91%	90%	92%	90%	100%	100%
CC - Two on Three on One Frame F Technology	100%	89%	87%	90%	85%	93%
CT - First & Second Generation Aero (P&W FT 4)	98%	90%	90%	90%	86%	97%
CT - First & Second Generation Frame B	99%	99%	95%	94%	90%	97%
CT - Second Generation Frame E	100%	91%	90%	94%	94%	100%
CT - Third Generation Aero	74%	99%	99%	90%	73%	96%
CT - Third Generation Frame F	100%	96%	93%	92%	90%	97%
Diesel	100%	98%	91%	85%	74%	93%
Hydro and Pumped Storage	100%	100%	100%	100%	100%	100%
Nuclear	0%	0%	0%	0%	0%	0%
Oil or Gas Steam	95%	90%	68%	69%	77%	88%
Sub-Critical Coal	80%	94%	76%	48%	60%	80%
Super Critical Coal	77%	100%	80%	39%	64%	87%

Table 7-36 Profile of units that did not recover avoidable costs from total market revenues or did not clear the 16/17 BRA or 17/18 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2014 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	9	340	1,889	12,662	27
Coal	7	4,844	7,184	10,019	46
Diesel	3	33	3,261	11,267	23
Oil or Gas Steam	3	1,730	2,043	12,447	35
Total	22	6,946	3,197	11,391	34

Table 12-6 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,129.2
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	2,949.3
Planned Retirements 2014	323.0
Planned Retirements 2015	10,313.0
Planned Retirements Post-2015	2,140.8
Total	26,679.8

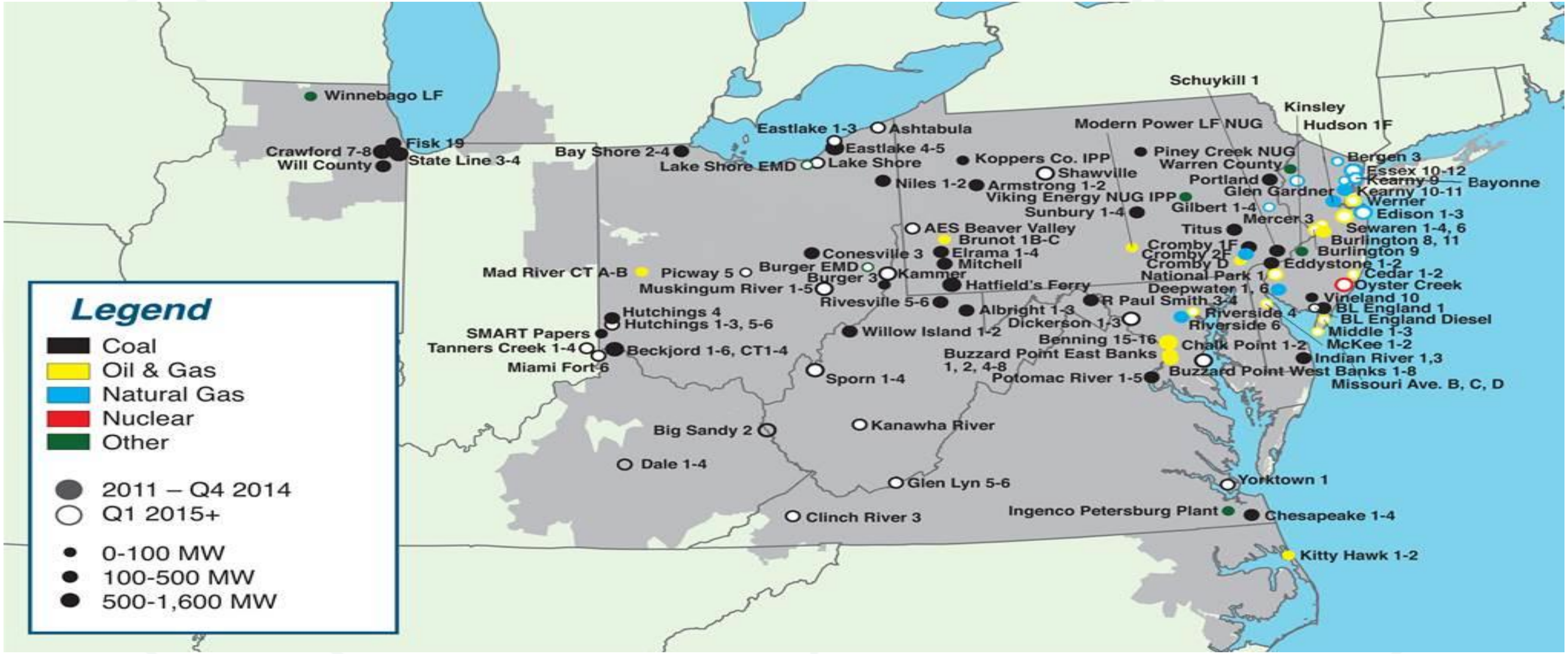
Table 12-9 Unit deactivations in 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
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
Duke Energy	Walter C Beckjord 4	150.0	Coal	DEOK	56	17-Jan-14
Modern Mallard Energy	Modern Power Landfill NUG	8.0	LFG	Met-Ed	56	03-Feb-14
Rockland Capital	BL England 1	113.0	Coal	AECO	51	01-May-14
Calpine Corporation	Deepwater 1	78.0	Natural gas	AECO	55	31-May-14
Calpine Corporation	Deepwater 6	80.0	Natural gas	AECO	60	01-Jun-14
NRG Energy	Portland 1	158.0	Coal	Met-Ed	56	01-Jun-14
NRG Energy	Portland 2	243.0	Coal	Met-Ed	52	01-Jun-14
Exelon Corporation	Riverside 6	115.0	Natural gas	BGE	44	01-Jun-14
PSEG	Burlington 9	184.0	Kerosene	PSEG	42	01-Jun-14
Corona Power	Sunbury 1-4	347.0	Coal	PPL	63	18-Jul-14
Integrys Energy	Winnebago Landfill	6.4	LFG	ComEd	07	01-Nov-14
Duke Energy	Walter C Beckjord 5-6	652.0	Coal	DEOK	49	01-Oct-14
Dominion	Chesapeake 1-4	576.0	Coal	Dominion	57	23-Dec-14
Duke Energy	Walter C Beckjord GT1-4	188.0	Coal	DEOK	43	25-Dec-14
PSEG	Kinsley Landfill	0.9	LFG	PSEG	30	31-Dec-14
Total		2,949.3				

Table 12-7 Planned deactivations of PJM units, as of December 31, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Eastlake 1-3	ATSI	327.0	Coal	Steam	15-Apr-15
Lake Shore 18	ATSI	190.0	Coal	Steam	15-Apr-15
Lake Shore EMD	ATSI	4.0	Diesel	Diesel	15-Apr-15
Will County	ComEd	251.0	Coal	Steam	15-Apr-15
Dale 1-4	EKPC	195.0	Coal	Steam	16-Apr-15
Shawville 1-4	PENELEC	603.0	Coal	Steam	16-Apr-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	01-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	31-May-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Big Sandy 2	AEP	800.0	Coal	Steam	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
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
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Miami Fort 6	DEOK	163.0	Coal	Steam	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
Riverside 4	BGE	74.0	Natural gas	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
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Burger EMD	ATSI	6.3	Diesel	Diesel	31-May-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-18
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		12,776.8			

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



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	
		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			
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 2014

	Total Energy Uplift Charges (Millions)	Annual Change (Millions)	Annual Percent Change	Energy Uplift as a Percent of Total PJM Billing
1999	$133.9	NA	NA	7.5%
2000	$217.0	$83.1	62.1%	9.6%
2001	$284.0	$67.1	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.5%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.5)	(32.0%)	1.2%
2010	$622.8	$300.1	93.0%	1.8%
2011	$605.0	($17.8)	(2.9%)	1.7%
2012	$640.6	$35.6	5.9%	2.2%
2013	$868.4	$227.8	35.6%	2.6%
2014	$964.7	$96.3	11.1%	1.9%

Figure 4-8 Energy uplift charges change from 2013 to 2014 by category

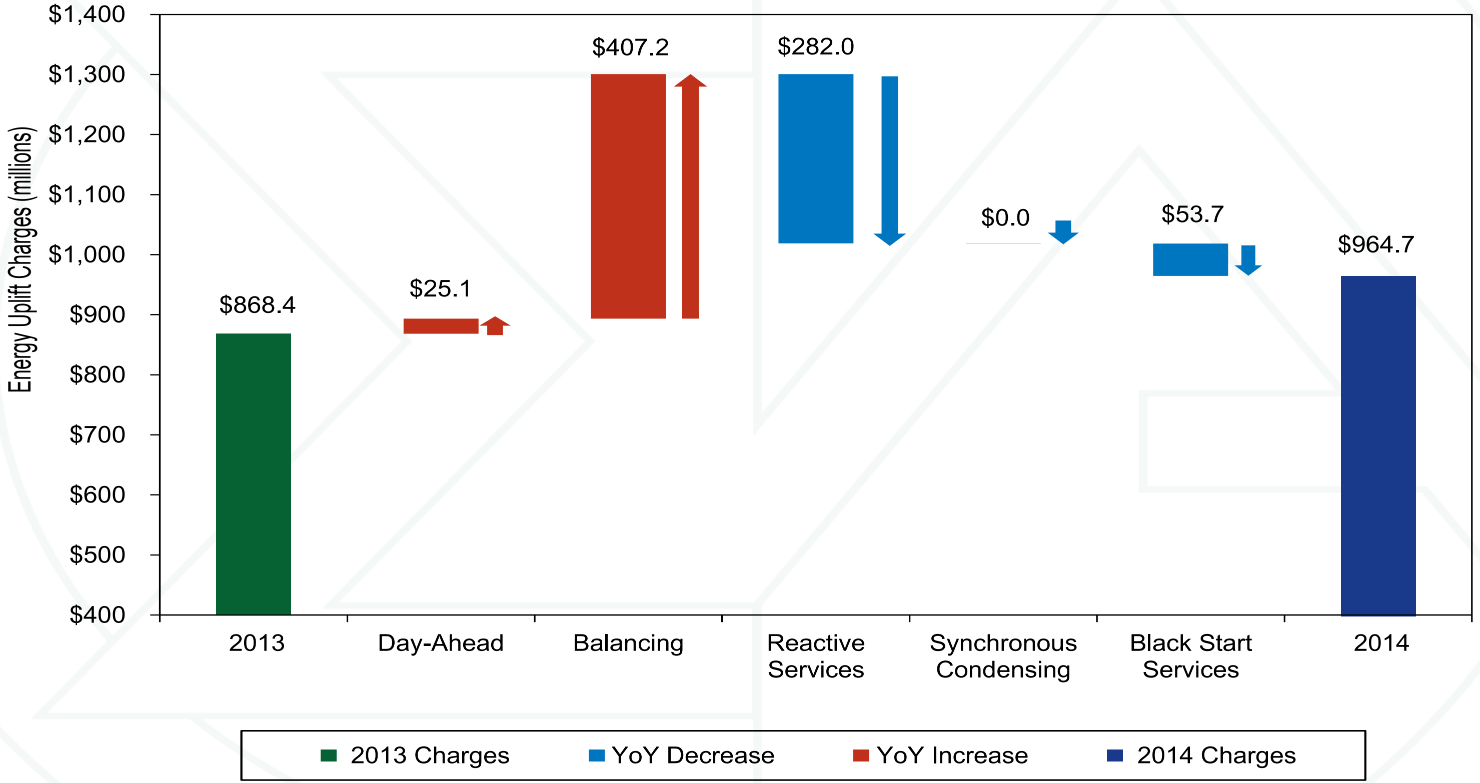


Figure 4-12 Energy uplift charges change from 2013 to 2014 by contributing factor

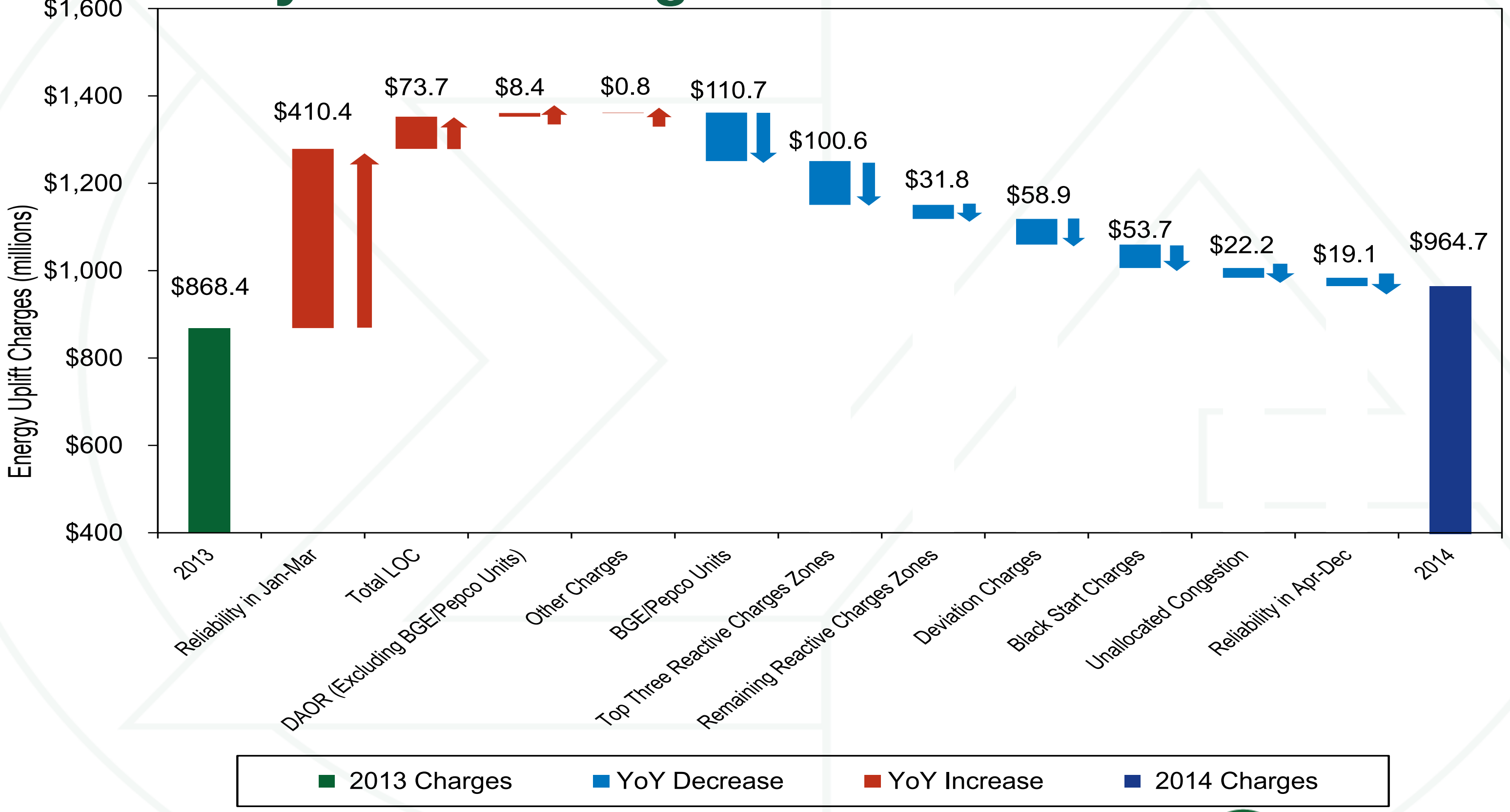


Table 4-23 Top 10 energy uplift credits units (By percent of total system): 2001 through 2014

	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	37.3%	0.7%
2014	33.6%	0.7%

Table 4-16 Operating reserve rates statistics ($/MWh): 2014

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	42.256	2.295	0.010	4.924
	DEC	43.005	2.424	0.107	5.031
	DA Load	1.689	0.129	0.000	0.168
	RT Load	24.630	0.450	0.000	2.358
	Deviation	42.256	2.295	0.010	4.924
West	INC	43.729	2.089	0.010	4.809
	DEC	44.478	2.219	0.107	4.917
	DA Load	1.689	0.129	0.000	0.168
	RT Load	24.652	0.439	0.000	2.358
	Deviation	43.729	2.089	0.010	4.809

Table 4-43 Current and proposed average energy uplift rate by transaction: 2013 and 2014

	Transaction	2013 Current Rates ($/MWh)	2013 Proposed Rates - 50% UTC ($/MWh)	2013 Proposed Rates - 0% UTC ($/MWh)	2014 Current Rates ($/MWh)	2014 Proposed Rates - 50% UTC ($/MWh)	2014 Proposed Rates - 0% UTC ($/MWh)
East	INC	3.286	0.480	1.121	2.295	0.223	0.698
	DEC	3.391	0.480	1.121	2.424	0.223	0.698
	DA Load	0.105	0.010	0.013	0.129	0.019	0.024
	RT Load	0.076	0.109	0.109	0.450	0.460	0.460
	Deviation	3.286	1.234	1.873	2.295	1.316	1.787
West	INC	1.653	0.104	0.343	2.089	0.184	0.584
	DEC	1.758	0.104	0.343	2.219	0.184	0.584
	DA Load	0.105	0.010	0.013	0.129	0.019	0.024
	RT Load	0.056	0.099	0.099	0.439	0.460	0.460
	Deviation	1.653	0.667	0.903	2.089	1.231	1.626
UTC	East to East	NA	0.961	2.242	NA	0.446	1.397
	West to West	NA	0.208	0.685	NA	0.369	1.168
	East to/from West	NA	0.585	1.464	NA	0.407	1.282

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
  - Improve measurement and verification.
    - Bankrupt customers as DR?
  - Compliance should include both increases and decreases in usage when called

Table 6-1 Overview of demand response programs

	Emergency Load Response Program			Economic Load Response Program
	Load Management (LM)			
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
Energy Payments	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 and MWh by month: 2010 through 2014

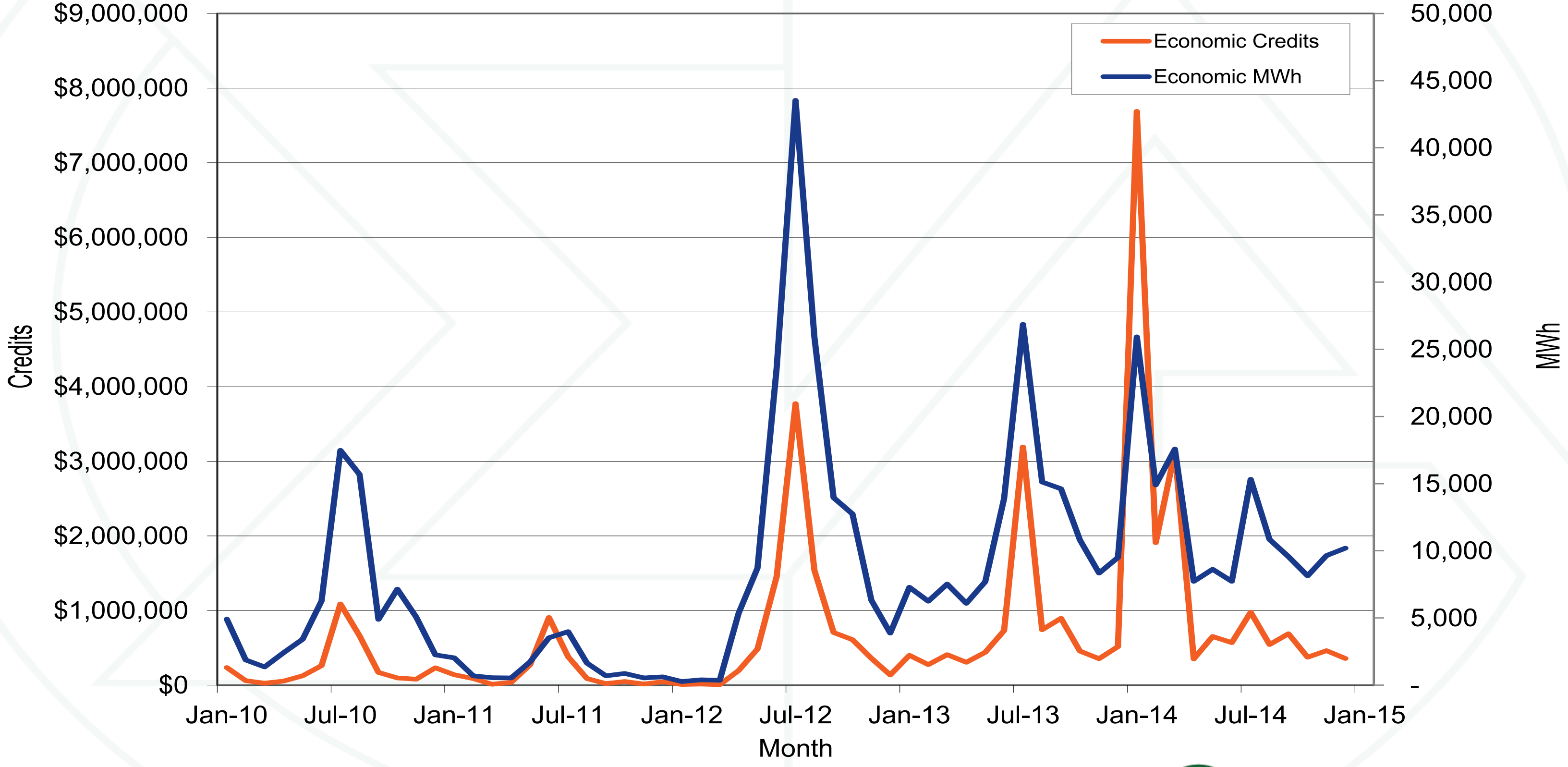


Figure 6-1 Demand response revenue by market: 2008 through 2014

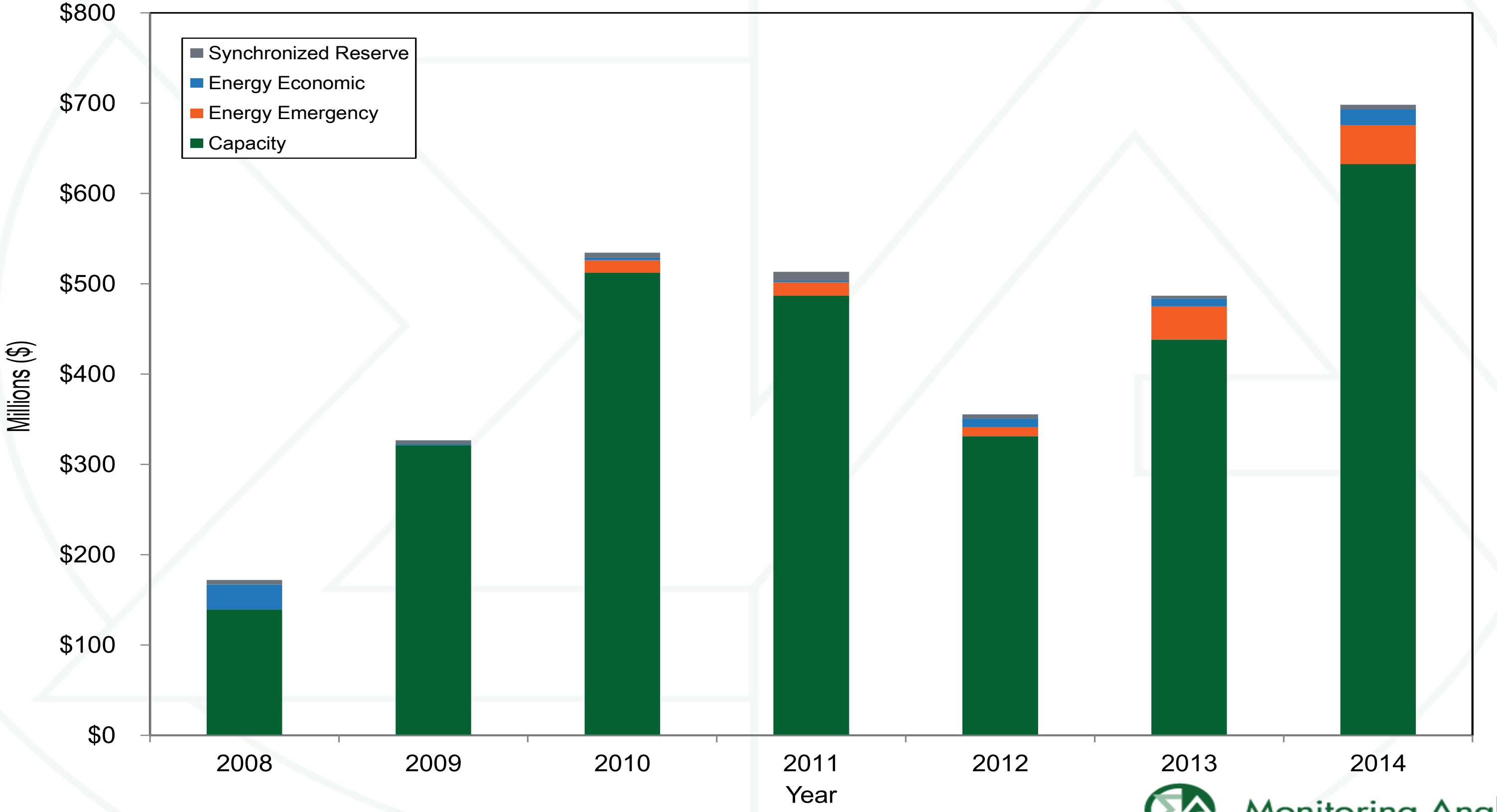
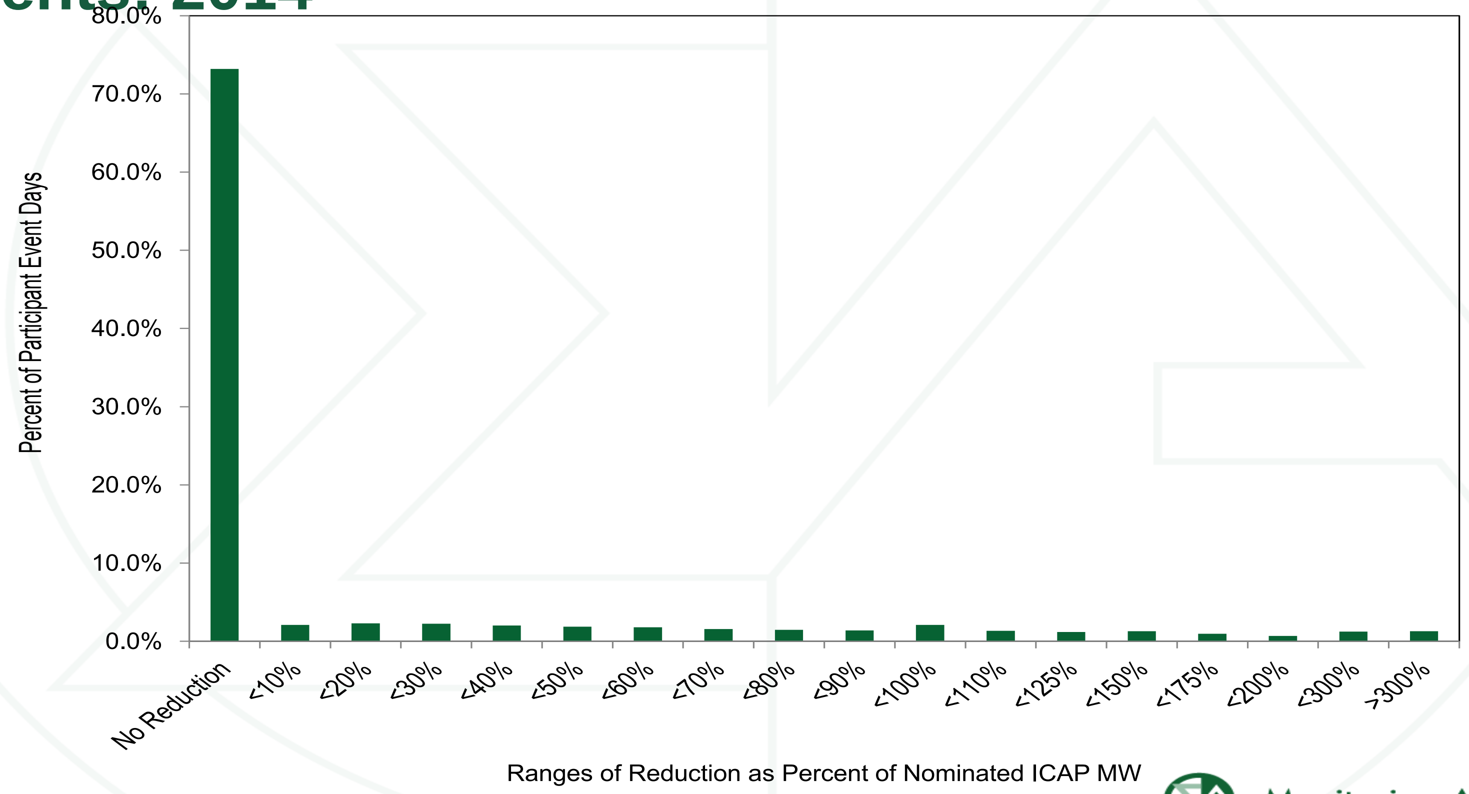


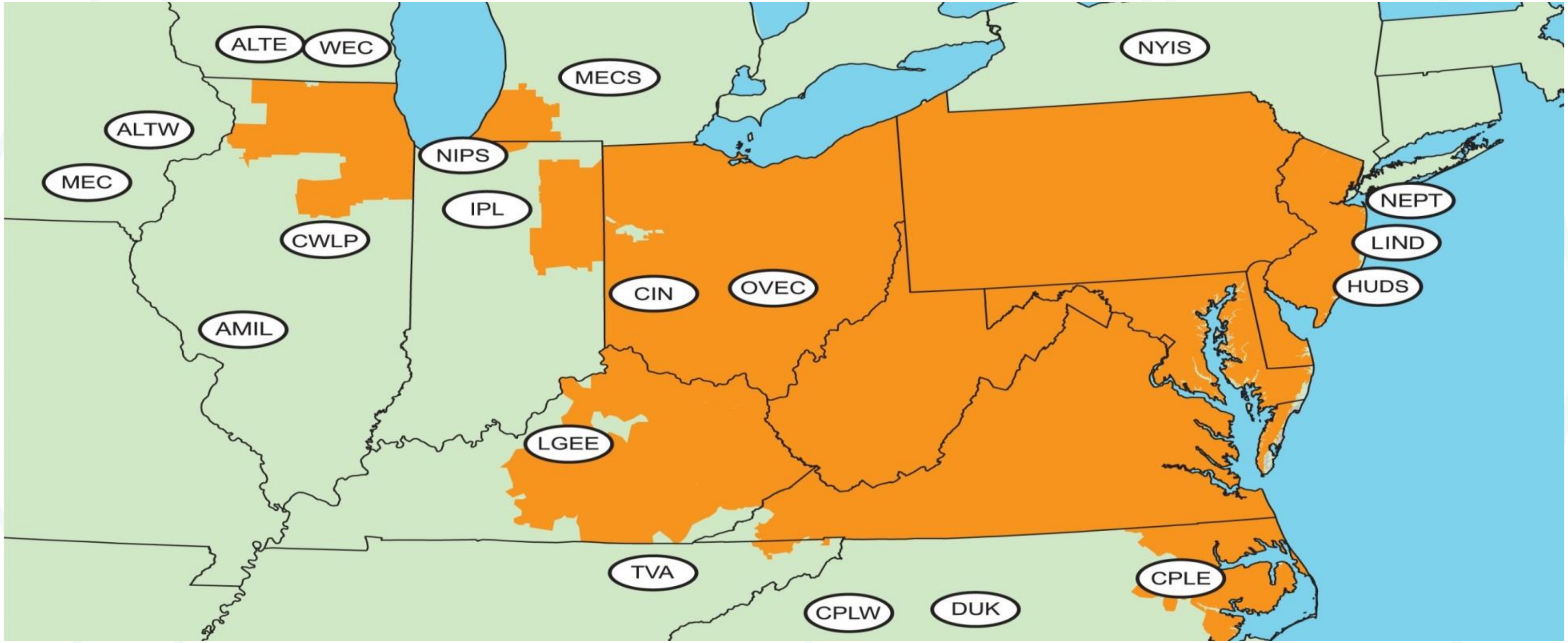
Figure 6-3 Distribution of participant event days across ranges of performance levels across the events: 2014



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



Monitoring Analytics

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2014

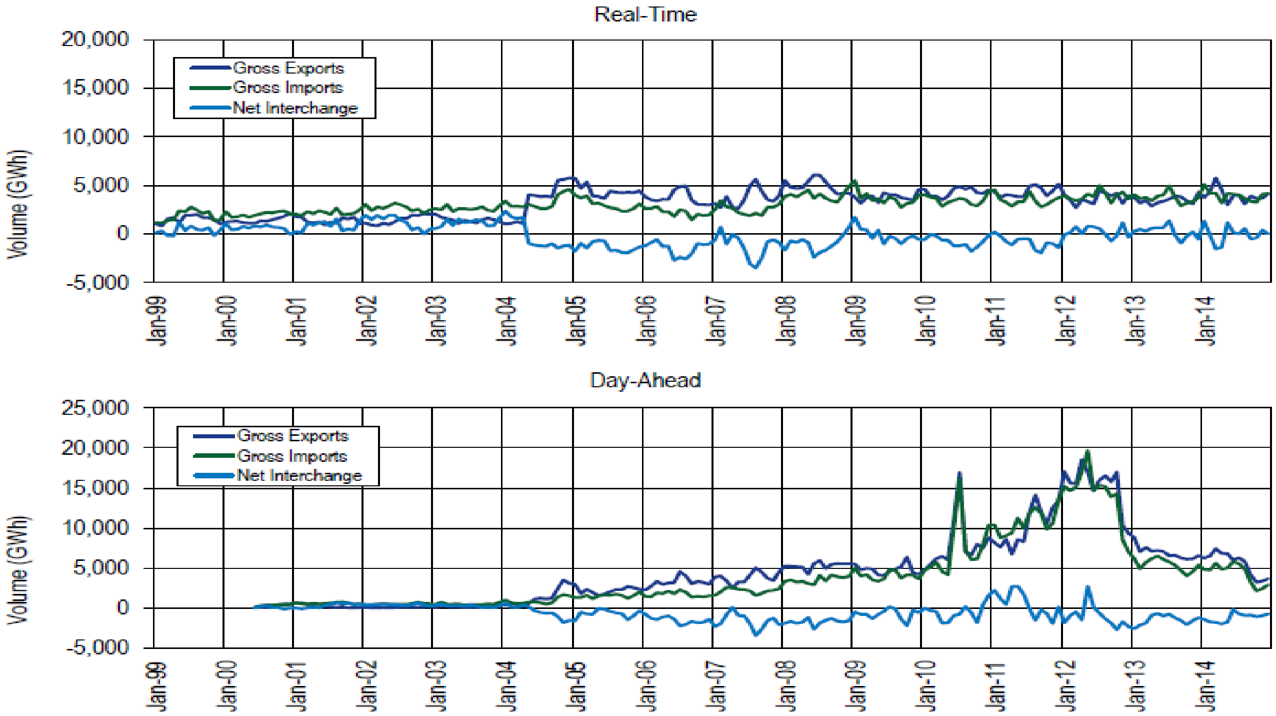


Table 10-1 The Regulation Market results were competitive

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

Table 10-2 The Tier 2 Synchronized Reserve Market results were competitive

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

Table 10-3 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.**
  - **Stop paying deselected tier 1 resources.**
  - **Implement explicit rules about tier 1 biasing**
  - **Use operating schedule to calculate LOC.**
  - **Replace day ahead DASR with real time DASR**

Table 10-4 History of ancillary services costs per MWh of Load: 2003 through 2014

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.50	$0.61	$0.24	$0.14	$0.83	$2.32
2004	$0.50	$0.60	$0.25	$0.13	$0.90	$2.38
2005	$0.79	$0.47	$0.26	$0.11	$0.93	$2.57
2006	$0.53	$0.48	$0.29	$0.08	$0.43	$1.81
2007	$0.63	$0.47	$0.29	$0.06	$0.58	$2.02
2008	$0.68	$0.40	$0.31	$0.08	$0.59	$2.06
2009	$0.34	$0.32	$0.37	$0.05	$0.48	$1.56
2010	$0.34	$0.38	$0.41	$0.07	$0.73	$1.93
2011	$0.32	$0.34	$0.42	$0.10	$0.77	$1.95
2012	$0.26	$0.40	$0.43	$0.04	$0.79	$1.92
2013	$0.24	$0.39	$0.80	$0.04	$0.59	$2.08
2014	$0.31	$0.37	$0.37	$0.20	$1.16	$2.41

Figure 10-27 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

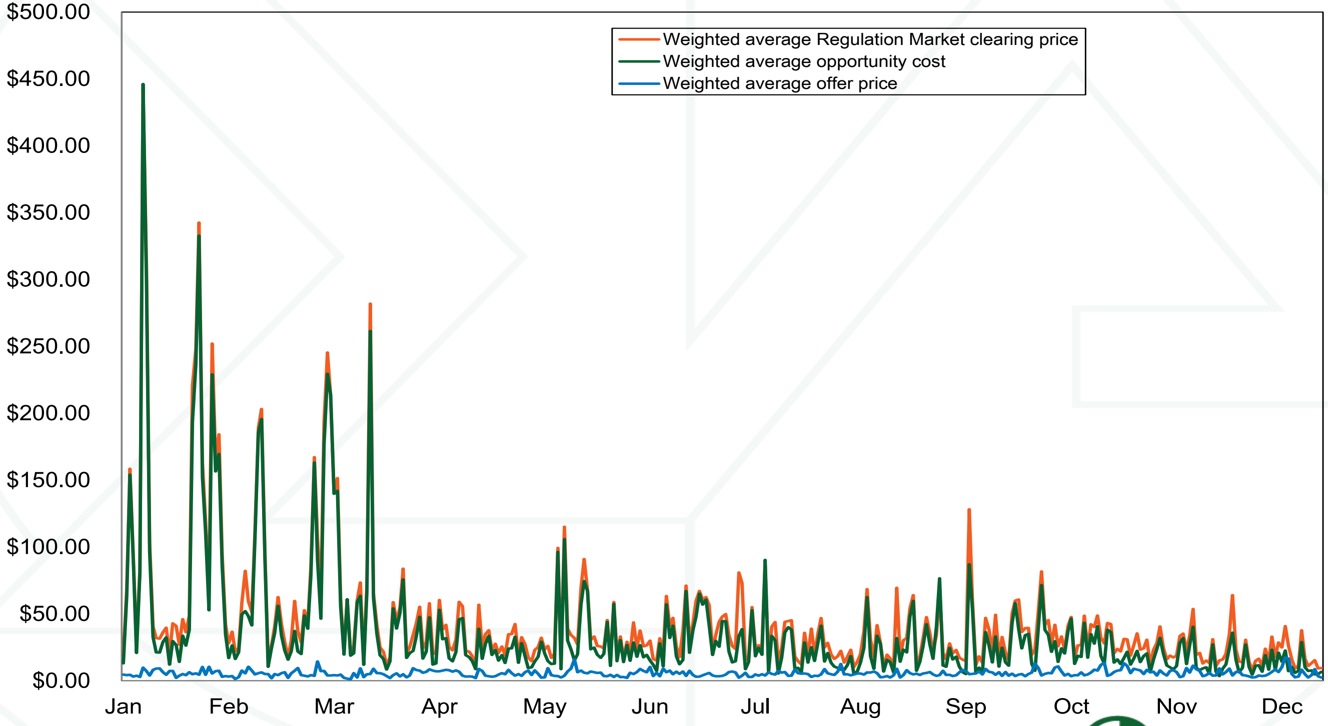


Table 10-41 Comparison of average price and cost for PJM Regulation, 2008 through 2014

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
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%
2014	$44.15	$53.41	83%

Table 10-38 Components of regulation cost: 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,677	$76.76	$5.71	$14.96	$97.43
Apr	395,612	$28.50	$4.49	$5.54	$38.53
May	397,411	$31.24	$4.64	$6.78	$42.66
Jun	387,102	$26.96	$4.57	$5.44	$36.97
Jul	395,865	$26.23	$4.74	$5.62	$36.59
Aug	401,673	$17.19	$4.34	$3.39	$24.91
Sep	382,207	$21.79	$4.45	$4.87	$31.10
Oct	395,073	$28.96	$5.47	$4.76	$39.19
Nov	385,812	$24.14	$4.45	$4.09	$32.68
Dec	392,470	$18.62	$3.58	$3.04	$25.24

Table 10-9 Tier 1 compensation rules: current

Hourly Parameters	Tier 1 Compensation by Type of Hour as Currently Implemented by PJM No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW
NSRMCP>$0	T1 credits = T2 SRMCP * calculated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MW)

Table 10-10 Tier 1 compensation rules: proposed

Hourly Parameters	Tier 1 Compensation by Type of Hour as Recommended by MMU No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW

Table 10-5 Average monthly tier 1 and tier 2 synchronized reserve, plus non-synchronized reserve used to satisfy the primary reserve requirement, MAD Subzone: 2014

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-synchronized Reserve MW
2014	Jan	242.6	1079.1	508.2
2014	Feb	841.5	467.9	643.2
2014	Mar	974.0	333.6	639.5
2014	Apr	877.4	510.2	522.6
2014	May	1049.4	282.3	621.3
2014	Jun	1089.0	219.0	626.8
2014	Jul	1215.9	91.6	701.8
2014	Aug	1055.5	247.1	696.4
2014	Sep	1019.1	282.9	592.9
2014	Oct	1042.5	344.4	533.3
2014	Nov	1017.2	288.3	591.2
2014	Dec	1087.4	227.8	571.9
2014	Average	959.3	364.5	604.1

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, full RTO Reserve Zone, 2014

Product	Share of Primary Reserve Requirement	MW Credited	Credits Paid	Price Per MW	Cost Per MW	All-In Cost
Tier 1 Synchronized Reserve Response	NA	17,962	$1,530,978	NA	$85.23	$0.00
Tier 1 Synchronized Reserve	19.3%	2,356,785	$89,719,045	$38.07	$38.07	$0.11
Tier 2 Synchronized Reserve	28.6%	3,485,894	$69,733,658	$12.94	$20.00	$0.09
Non-synchronized Reserve	52.1%	6,357,945	$13,515,036	$0.87	$2.13	$0.02
Primary Reserve	100.0%	12,200,624	$172,967,739	$11.50	$14.18	$0.22

Figure 10-6 Average hourly tier 1 actual MW vs average hourly estimated tier 1 MW, 2014

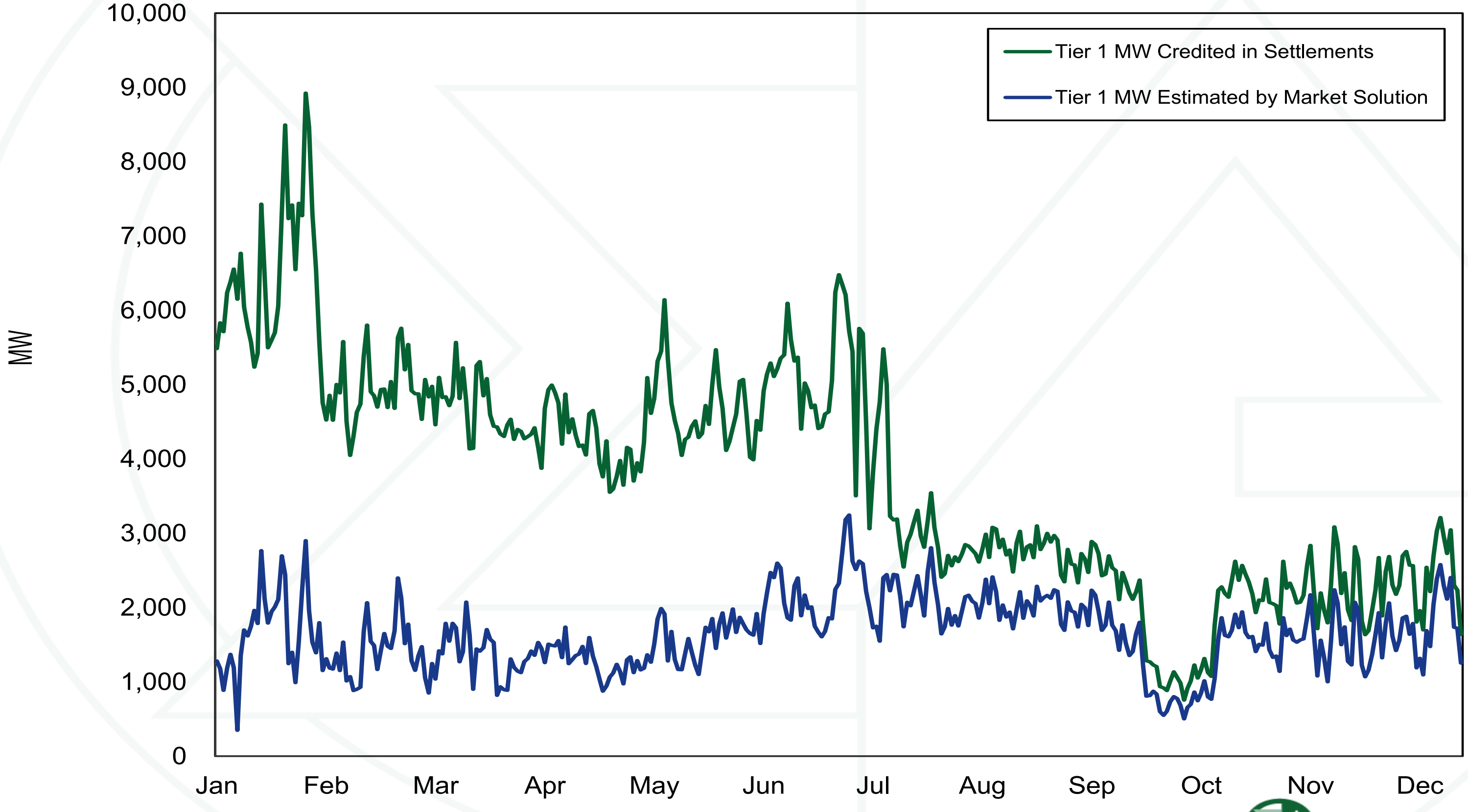


Table 13-1 The FTR Auction Markets results were competitive

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

State of the Market Report Recommendations

- **ARRs/FTRs**
  - **Address Stage 1A overallocation**
  - **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 13-12 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2014

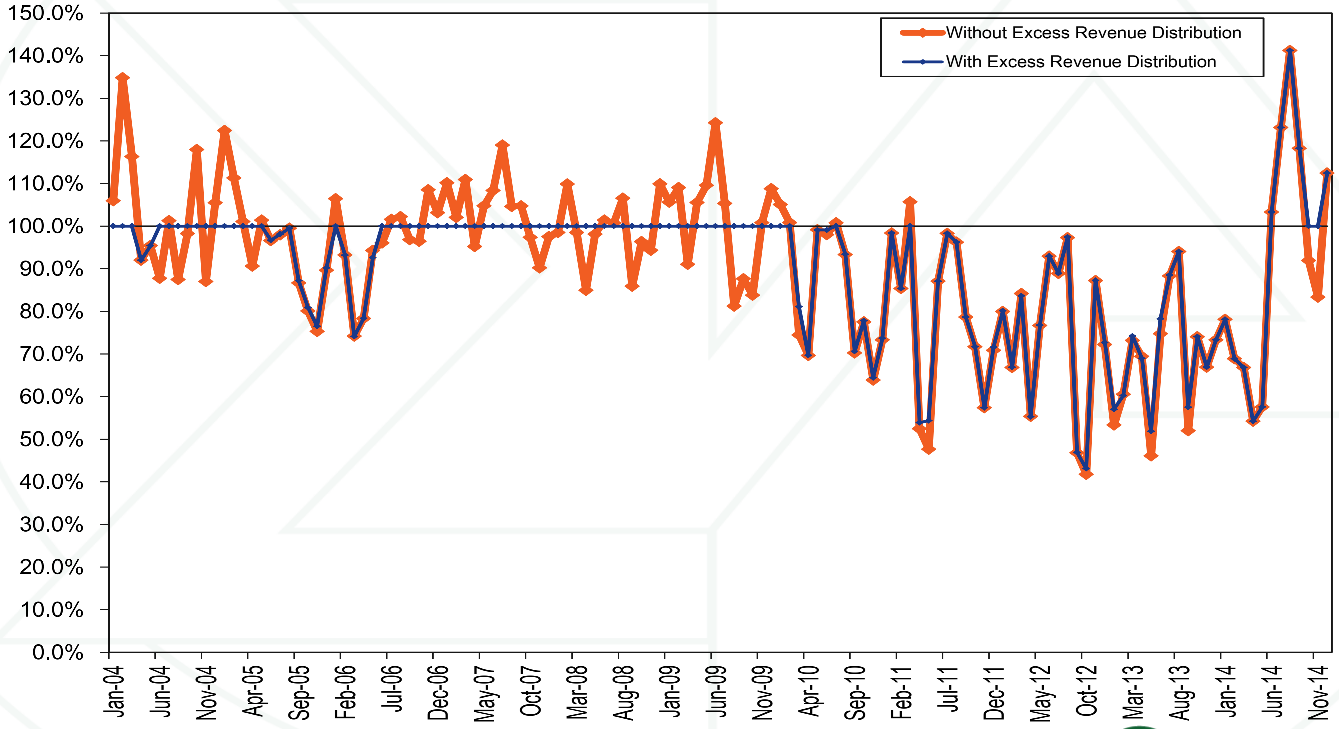


Figure 13-15 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2014 to 2015 planning periods

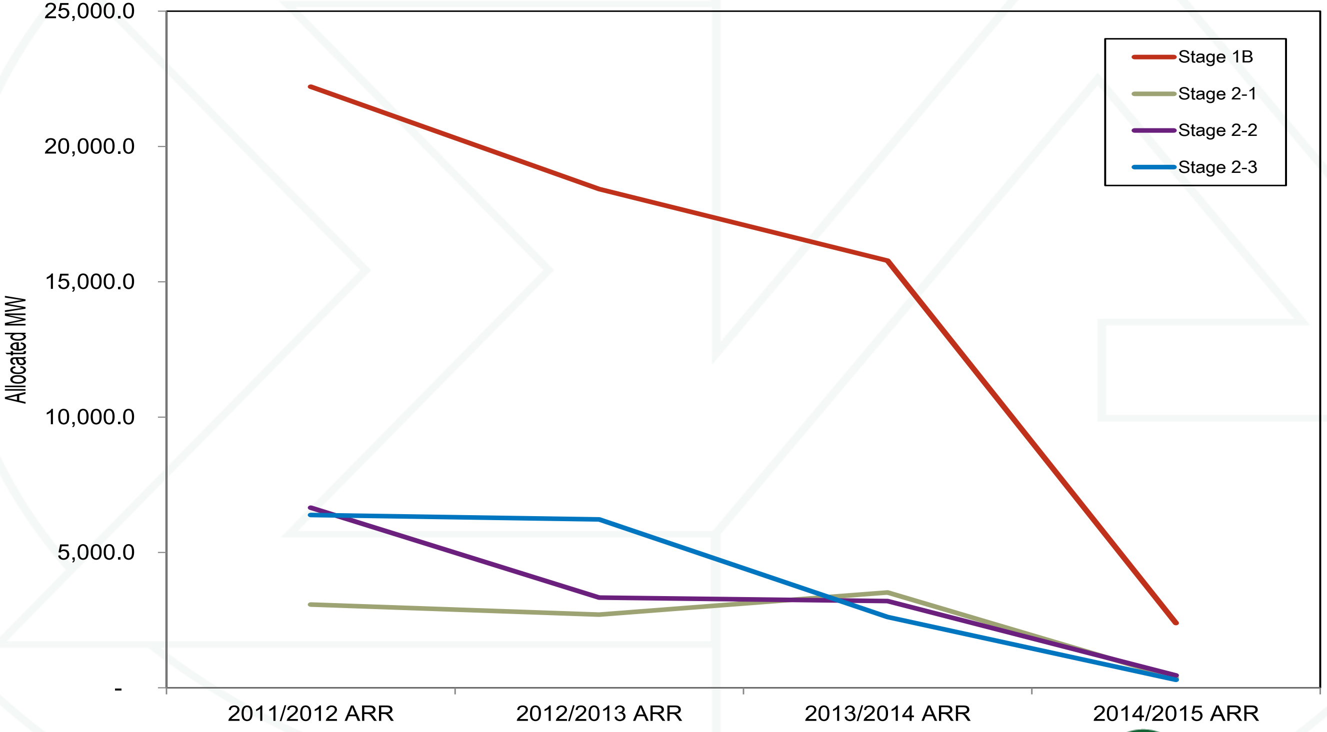


Figure 13-6 Annual FTR Auction volume: Planning period 2009 to 2010 through 2014 to 2015

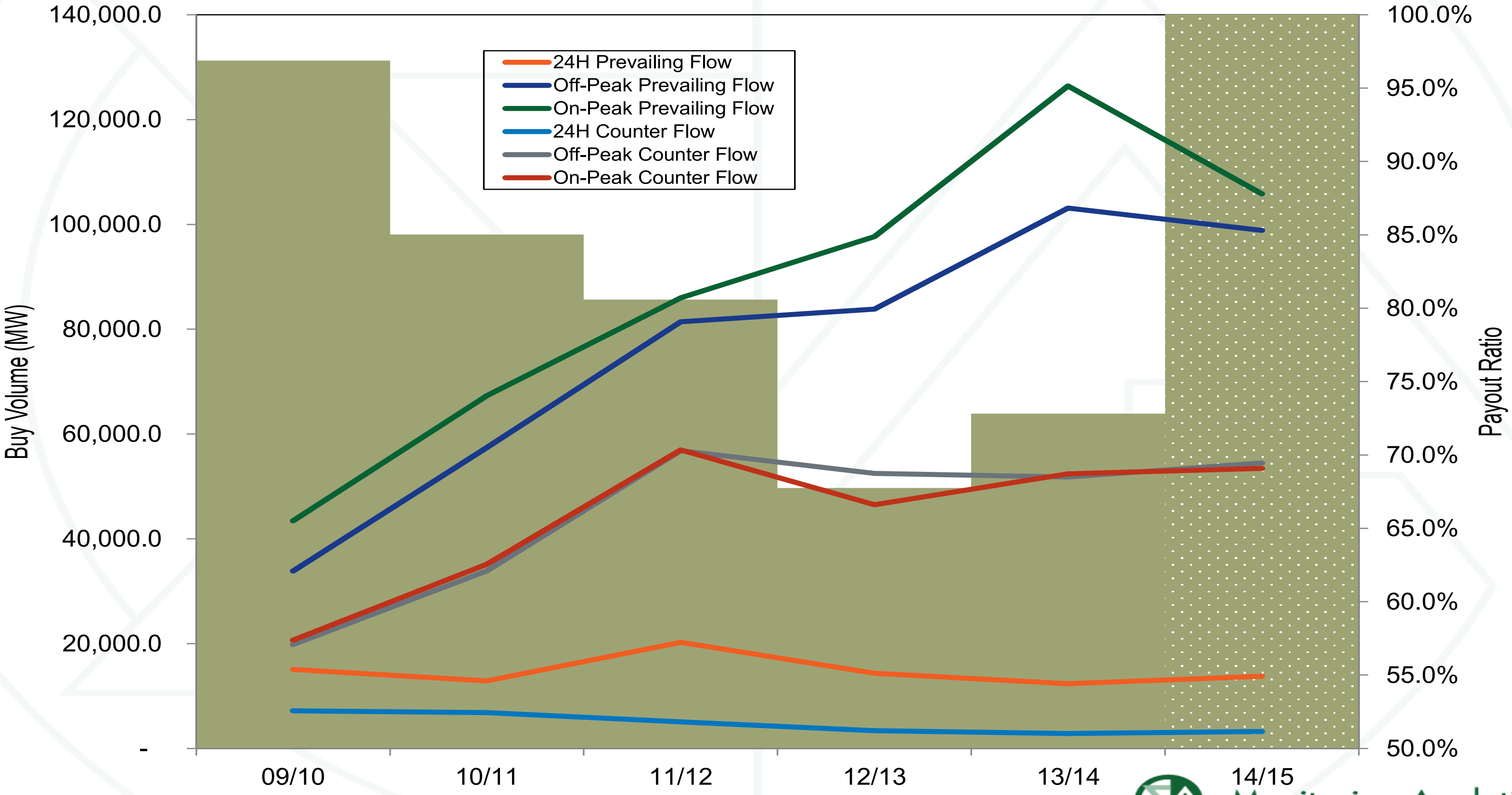


Figure 13-9 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through 2014 to 2015

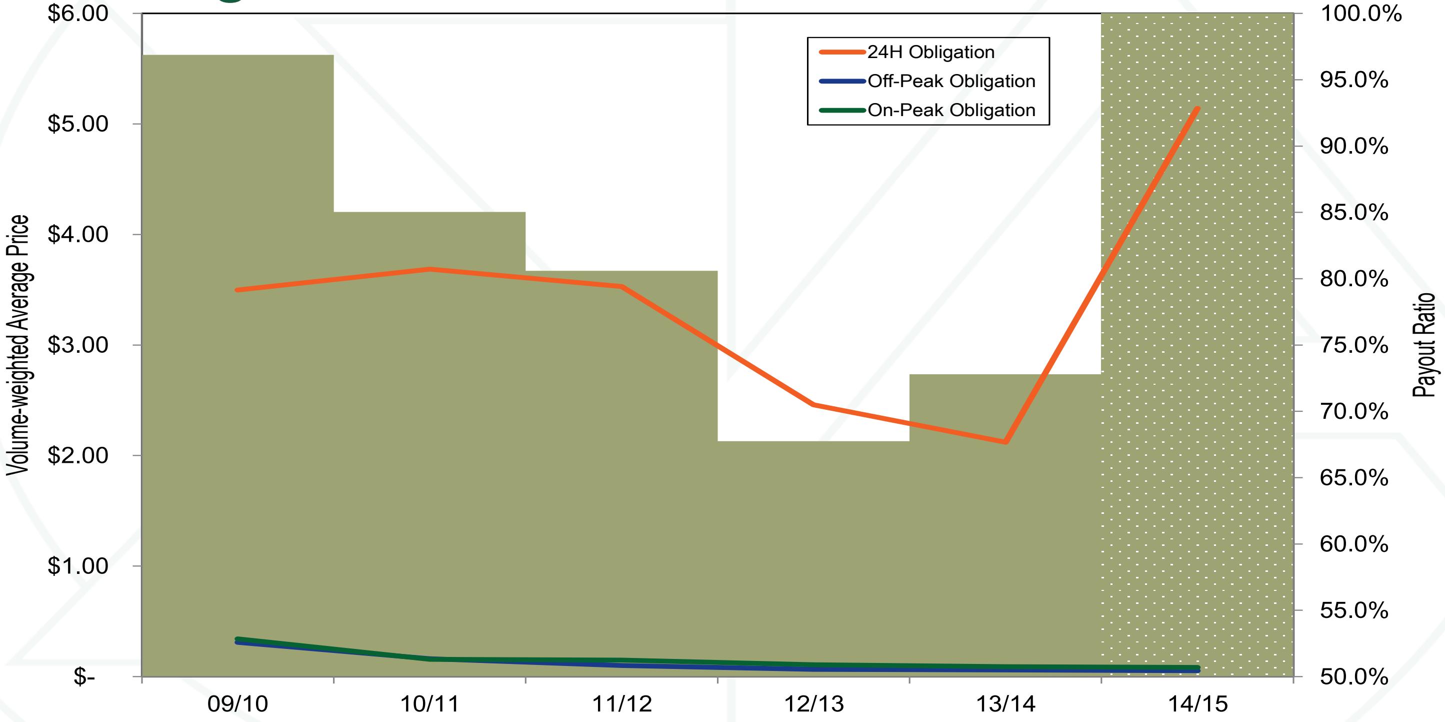


Figure 13-8 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2014

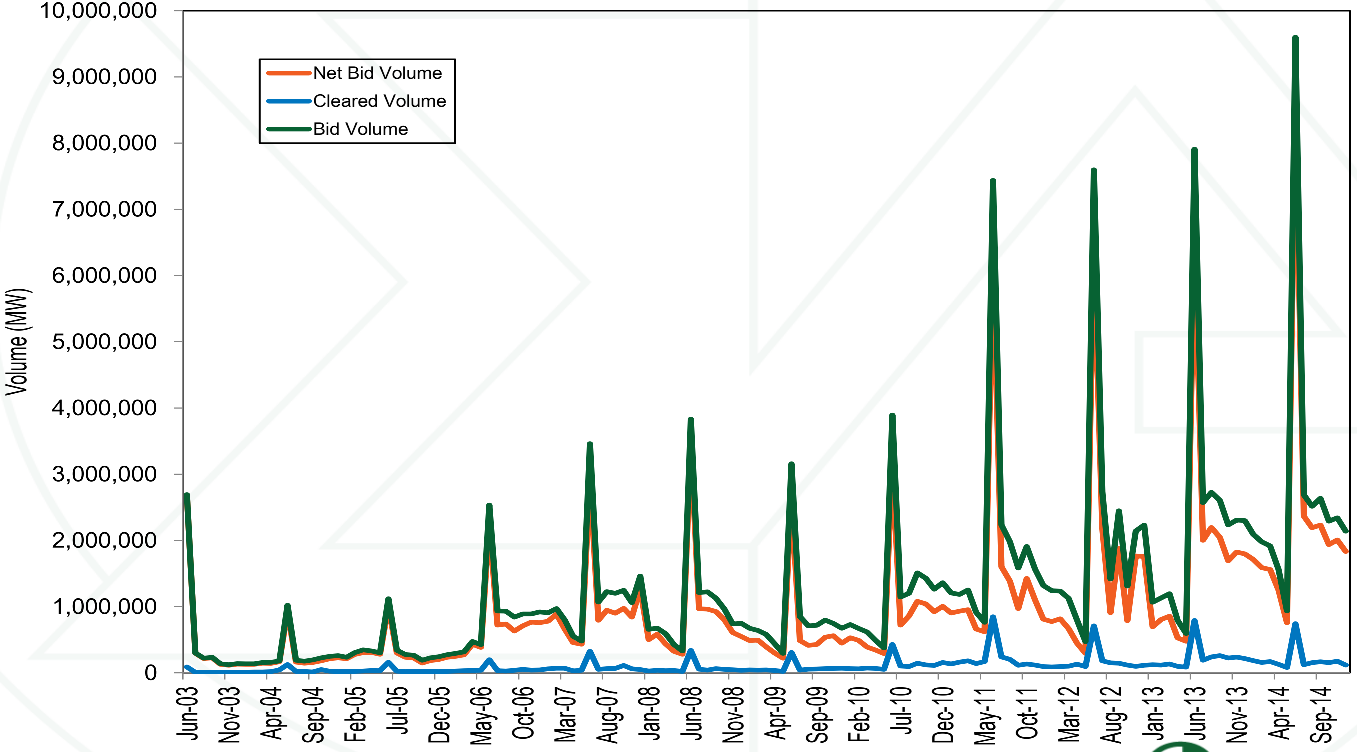


Figure 13-2 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2014

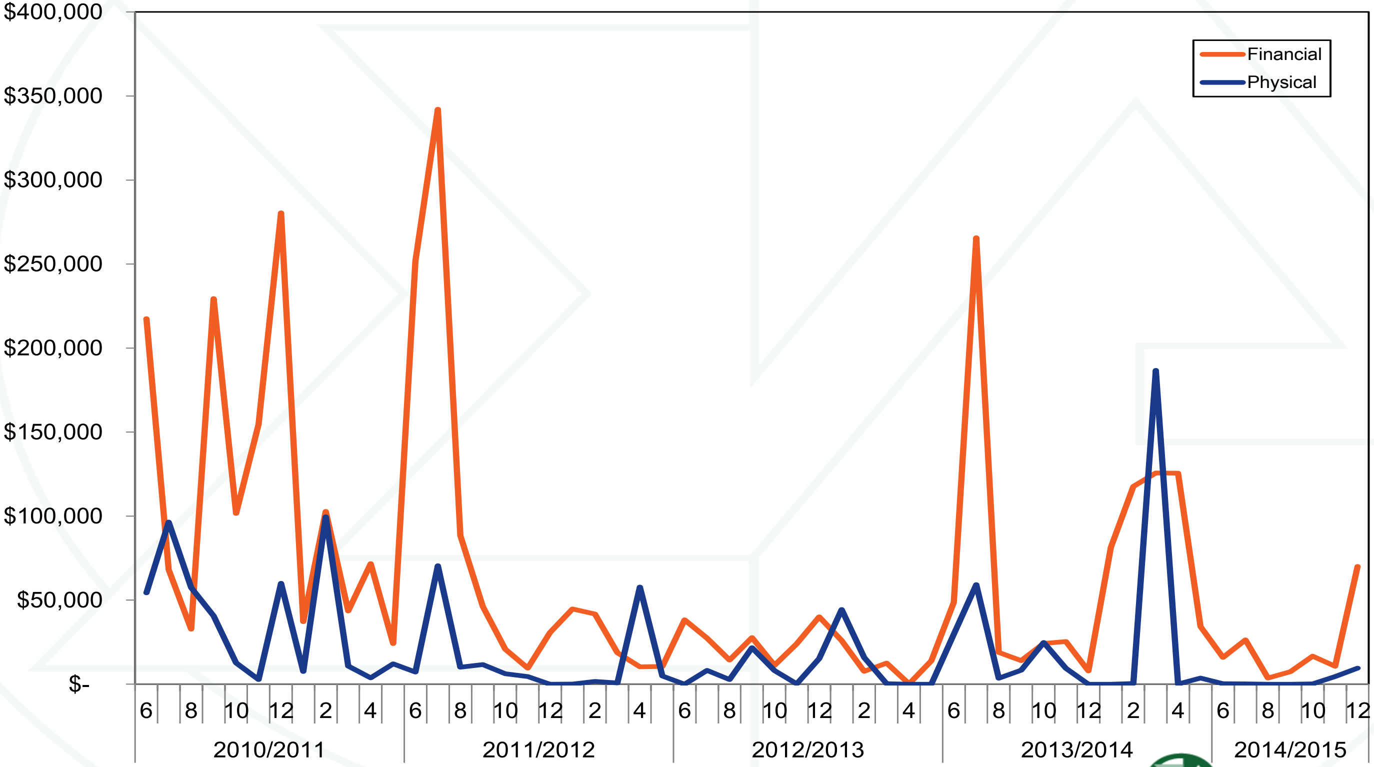


Figure 13-3 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2014

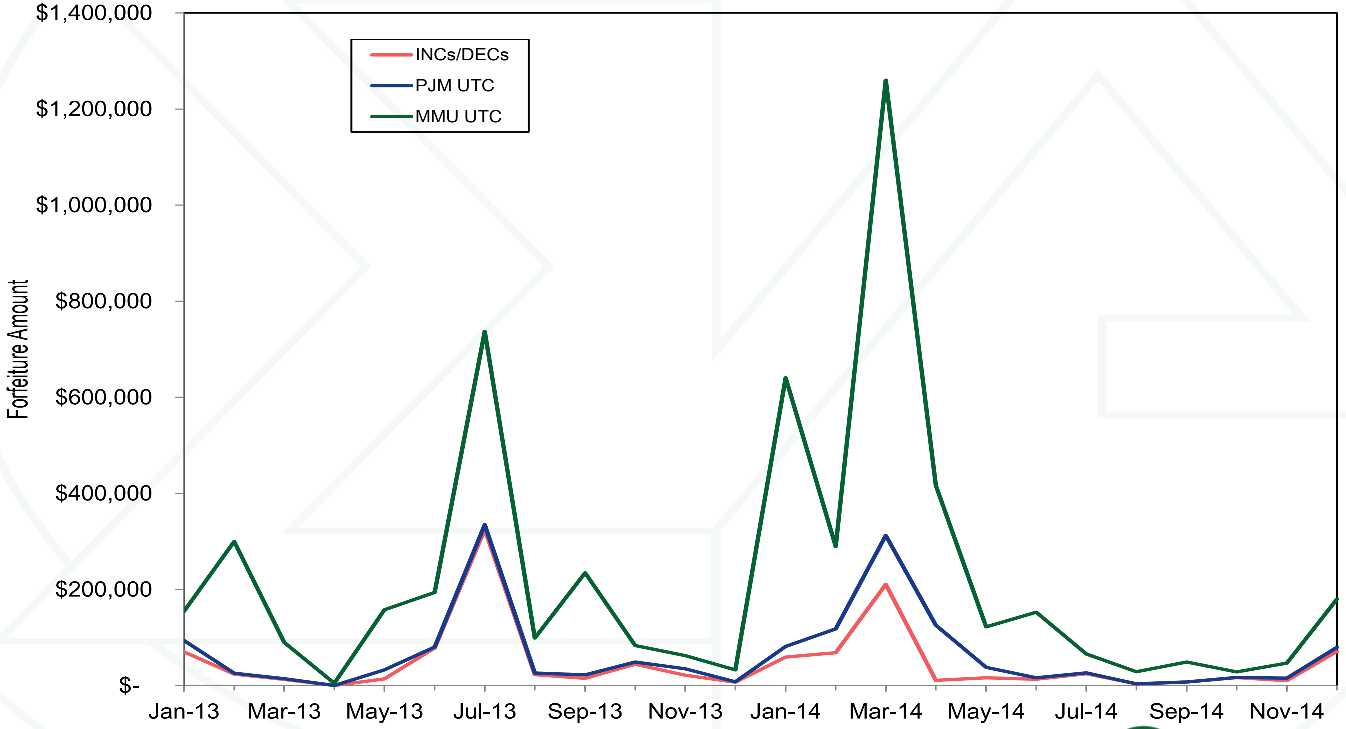


Table 13-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2014 to 2015

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	10.4%	0.6%	7.4%
		No	32.1%	19.5%	28.2%
		Total	42.5%	20.0%	35.6%
	Financial	No	57.5%	80.0%	64.4%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		28.2%	25.4%	27.4%
	Financial		71.8%	74.6%	72.6%
	Total		100.0%	100.0%	100.0%

Table 4-43 ARR and FTR congestion offset (in millions): Planning periods 2013 to 2014 and 2014 to 2015

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2013/2014	$522.3	$1,814.9	$598.8	$1,738.3	$1,771.0	($32.7)	98.2%
2014/2015*	$760.1	$553.2	$788.1	$525.2	$578.7	($53.5)	90.8%
* Shows first seven months through December 31, 2014							

Table 13-17 FTR profits by organization type and FTR direction: 2014

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$465,299,413	$473,053,519	($62,389,957)	($2,053,700)	$873,909,275
Financial	$519,565,439	NA	$24,076,663	NA	$543,642,102
Total	$984,864,851	$473,053,519	($38,313,294)	($2,053,700)	$1,417,551,377

Figure 3-26 PJM monthly cleared up-to congestion transactions by type (MW): 2005 through 2014

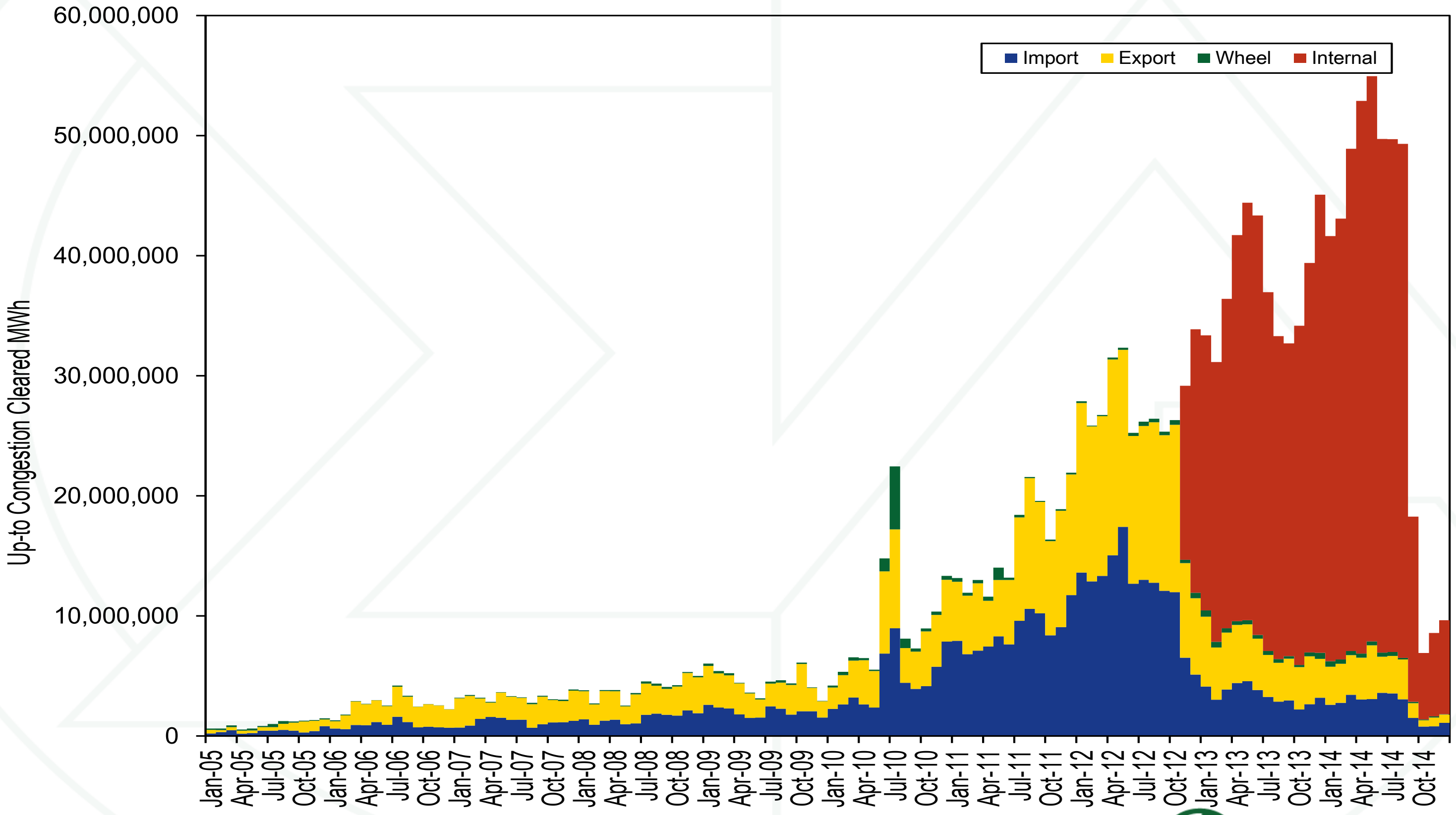


Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): 2013 and 2014

	2013		2014	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	432,126,914	95.6%	420,313,334	96.9%
Physical	19,875,032	4.4%	13,254,209	3.1%
Total	452,001,946	100.0%	433,567,543	100.0%

Market Monitoring Unit

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

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