2012 State of the Market Report for PJM

March 14, 2013

Washington DC

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
- 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

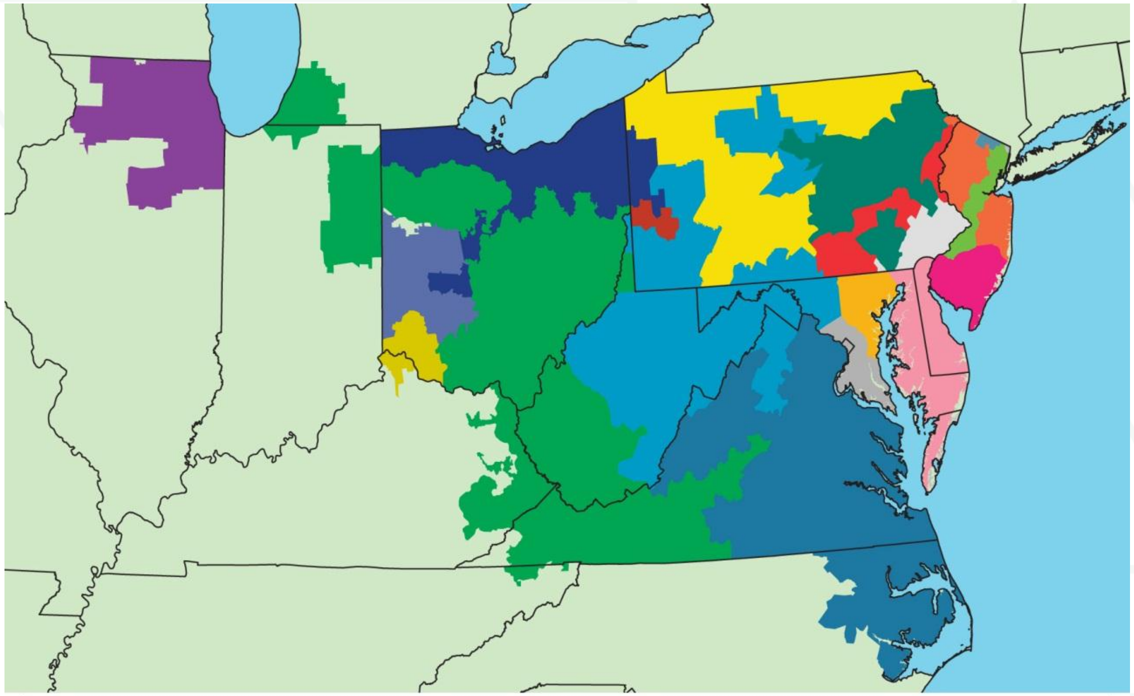
Role of Market Monitoring

- 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
- FERC has enforcement authority

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



Legend

- Allegheny Power Company (AP)
- American Electric Power Co., Inc (AEP)
- American Transmission Systems, Inc. (ATSI)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- ComEd
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duke Energy Ohio/Kentucky (DEOK)
- Duquesne Light (DLCO)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- Pennsylvania Electric Company (PENELEC)
- Pepco
- PPL Electric Utilities (PPL)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

Table 1-1 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**

Table 1-2 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: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

Table 1-3 The Regulation Market results were not competitive for the first three quarters and were indeterminate for the fourth quarter

	January through September, 2012		October through December, 2012	
Market Element	Evaluation	Market Design	Evaluation	Market Design
Market Structure	Not Competitive		Not Competitive	
Participant Behavior	Competitive		Competitive	
Market Performance	**Not Competitive**	**Flawed**	**To Be Determined**	**To Be Determined**

Table 1-4 The Synchronized Reserve Markets results were competitive

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

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

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

Table 1-6 The FTR Auction Markets results were competitive

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

State of the Market Recommendations

- **Capacity market**
  - **Eliminate 2.5 percent demand reduction.**
  - **Eliminate limited and summer unlimited products.**
  - **Improve performance incentives.**
  - **Eliminate OMC outages.**
  - **Require same modeling assumptions for all MOPR projects.**
- **Energy market**
  - **Eliminate FMU/AU adders.**

State of the Market Recommendations

- **Operating reserves**
  - **Improve process of identifying reasons for paying credits and allocating charges.**
  - **Use operating schedule to calculate energy LOC.**
  - **Treat start up and no load costs as costs.**
  - **Require up to congestion transactions to pay operating reserve charges, after analysis.**

State of the Market Recommendations

- **Demand response**
  - **DR should be classified as economic and not emergency program.**
  - **Improve measurement and verification and compliance reporting.**
- **Ancillary**
  - **Implement consistent treatment of marginal benefits factor in the Regulation Market.**
  - **Use operating schedule to calculate LOC.**

State of the Market Recommendations

- **Transactions**
  - **Require UTC to pay a fee during evaluation of operating reserves issues.**
  - **Implement rules to prevent sham scheduling.**
- **Planning**
  - **Remove projects from the queue if not viable.**
- **FTRs**
  - **Correct the reporting of payout ratio.**
  - **Eliminate portfolio netting.**
  - **Ensure symmetric treatment of counter flow FTRs for payout.**

Table 1-8 Total price per MWh by category and total revenues by category: 2011 and 2012

Category	2011 $/MWh	2012 $/MWh	Percent Change Totals	2011 Percent of Total	2012 Percent of Total
Load Weighted Energy	$45.94	$35.23	(23.3%)	73.4%	72.6%
Capacity	$9.72	$6.05	(37.7%)	15.5%	12.5%
Transmission Service Charges	$4.42	$4.78	8.3%	7.1%	9.9%
Operating Reserves (Uplift)	$0.79	$0.79	0.0%	1.3%	1.6%
Reactive	$0.42	$0.43	3.0%	0.7%	0.9%
PJM Administrative Fees	$0.37	$0.42	15.6%	0.6%	0.9%
Transmission Enhancement Cost Recovery	$0.29	$0.34	17.9%	0.5%	0.7%
Regulation	$0.32	$0.26	(20.2%)	0.5%	0.5%
Transmission Owner (Schedule 1A)	$0.09	$0.08	(11.0%)	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	(10.3%)	0.1%	0.1%
Synchronized Reserves	$0.09	$0.04	(55.2%)	0.1%	0.1%
Black Start	$0.02	$0.03	28.3%	0.0%	0.1%
NERC/RFC	$0.02	$0.02	19.6%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(5.4%)	0.0%	0.0%
Load Response	$0.01	$0.01	43.0%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(17.1%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00			0.0%
Total	$62.56	$48.55	(22.4%)	100.0%	100.0%

Figure 2-1 Average PJM aggregate supply curves: Summer 2011 and 2012

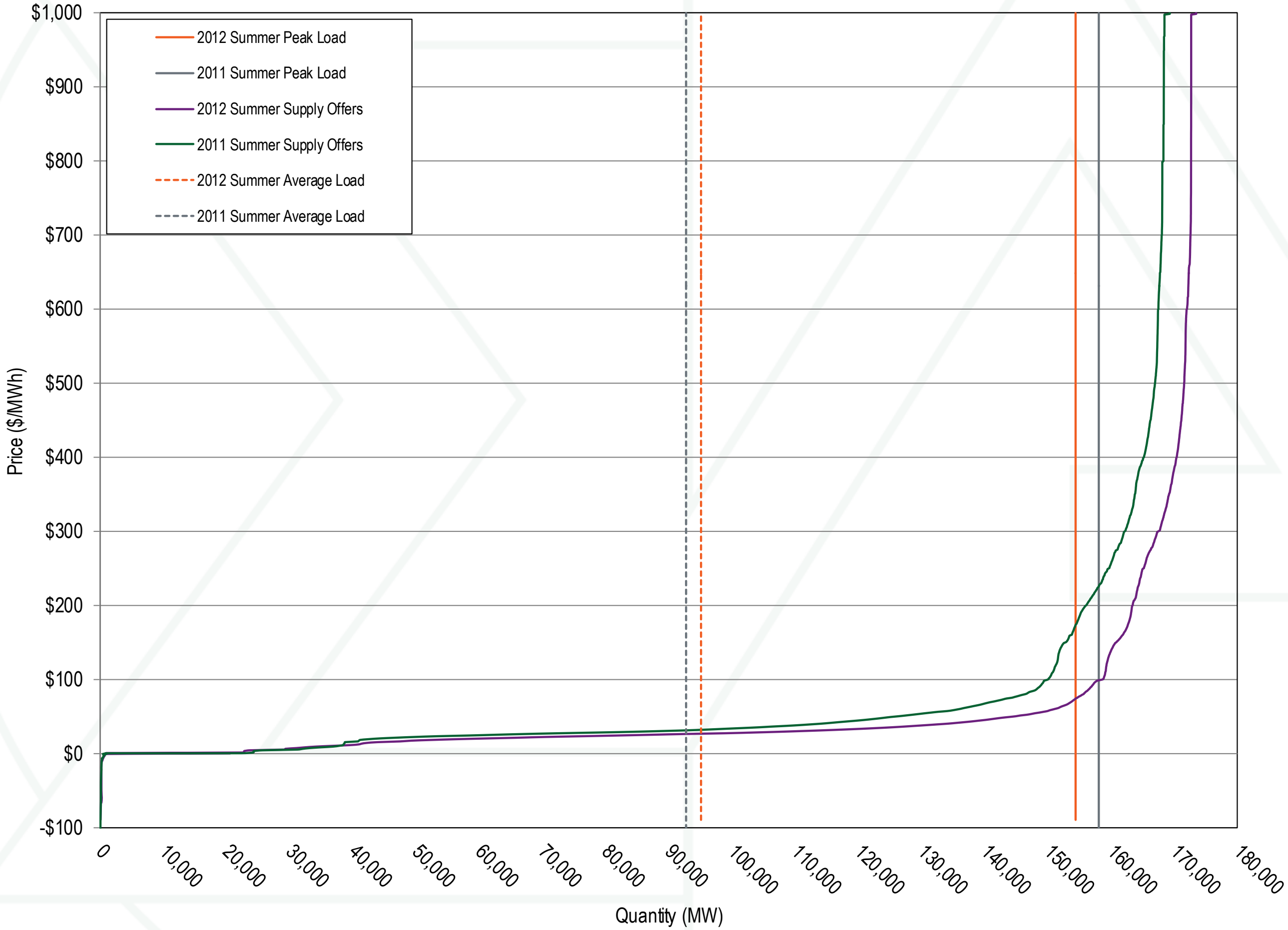


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Figure 2-2 PJM footprint calendar year peak loads: 1999 to 2012

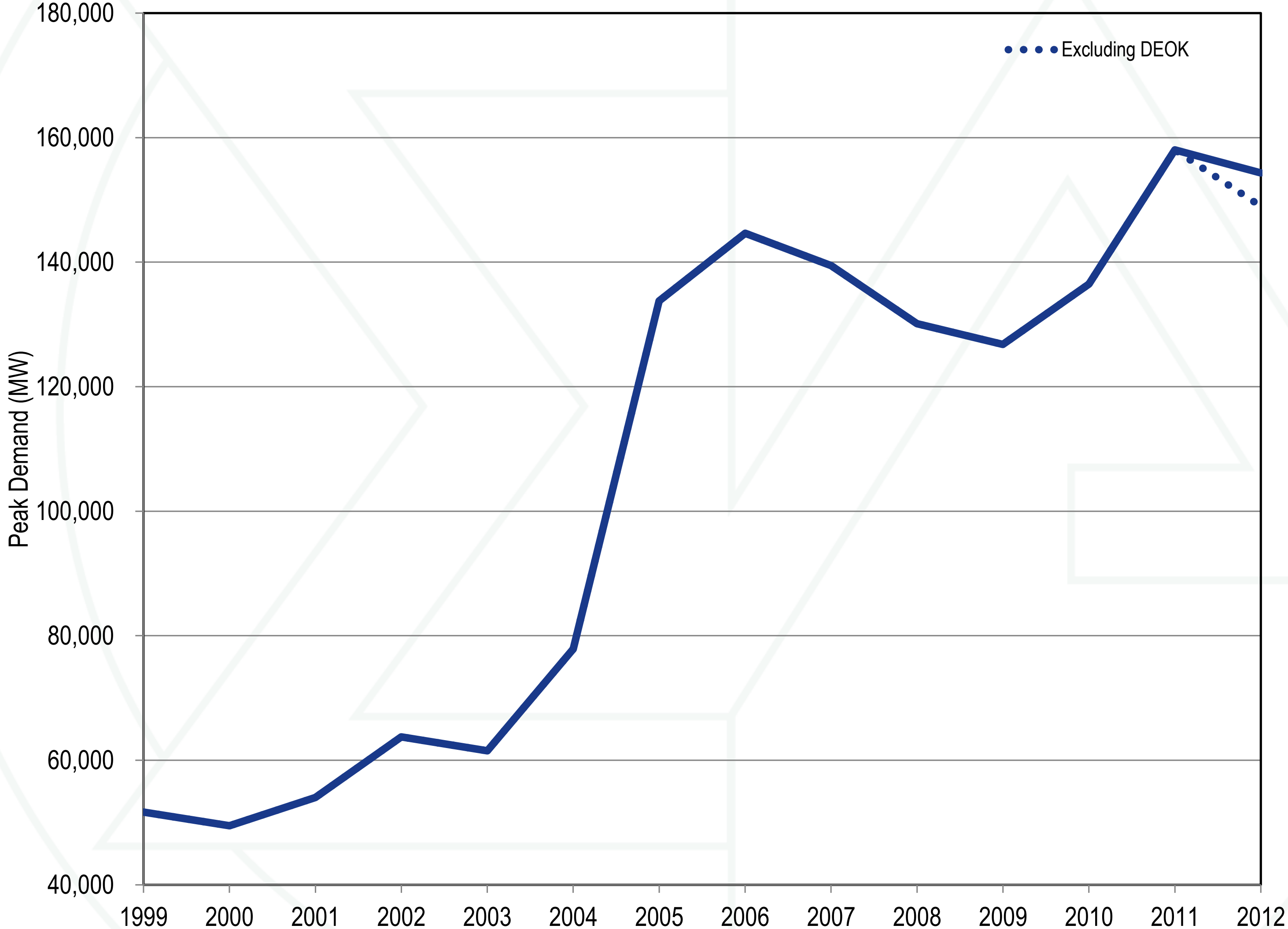


Table 2-7 Actual PJM footprint peak loads: 1999 to 2012

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 (with DEOK)	Tue, July 17	17	154,344	(3,672)	(2.3%)
2012 (without DEOK)	Tue, July 17	17	148,984	(9,032)	(5.7%)

Table 2-30 PJM real-time average hourly load: 1998 through 2012

	PJM Real-Time Load (MWh)		Year-to-Year Change	
Year	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,578	5,511	NA	NA
1999	29,641	5,955	3.7%	8.1%
2000	30,113	5,529	1.6%	(7.2%)
2001	30,297	5,873	0.6%	6.2%
2002	35,776	7,976	18.1%	35.8%
2003	37,395	6,834	4.5%	(14.3%)
2004	49,963	13,004	33.6%	90.3%
2005	78,150	16,296	56.4%	25.3%
2006	79,471	14,534	1.7%	(10.8%)
2007	81,681	14,618	2.8%	0.6%
2008	79,515	13,758	(2.7%)	(5.9%)
2009	76,034	13,260	(4.4%)	(3.6%)
2010	79,611	15,504	4.7%	16.9%
2011	82,546	16,156	3.7%	4.2%
2012	87,011	16,213	5.4%	0.3%

Figure 2-8 PJM real-time monthly average hourly load: 2011 and 2012

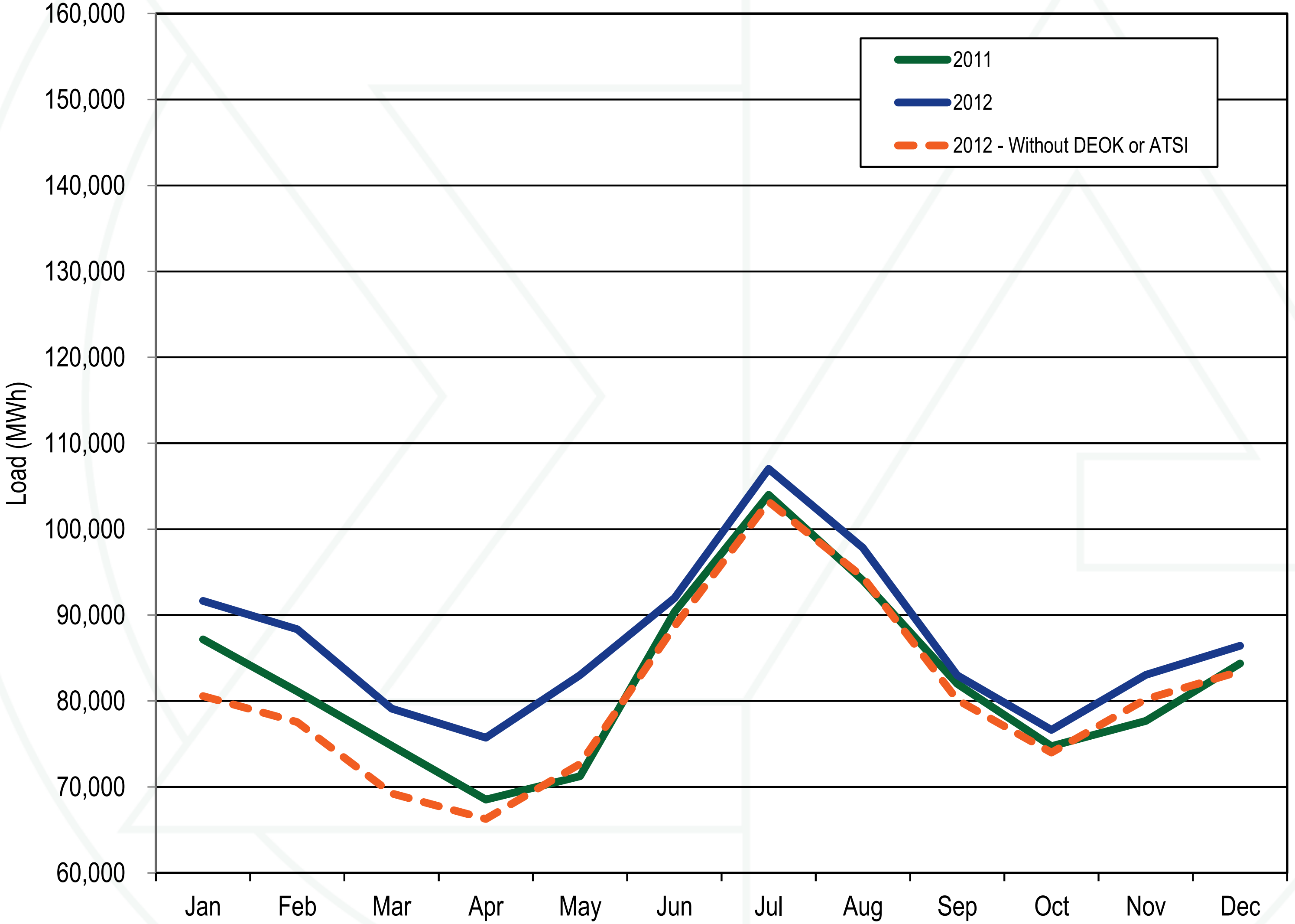


Table 2-38 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2012

	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%)

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through 2012

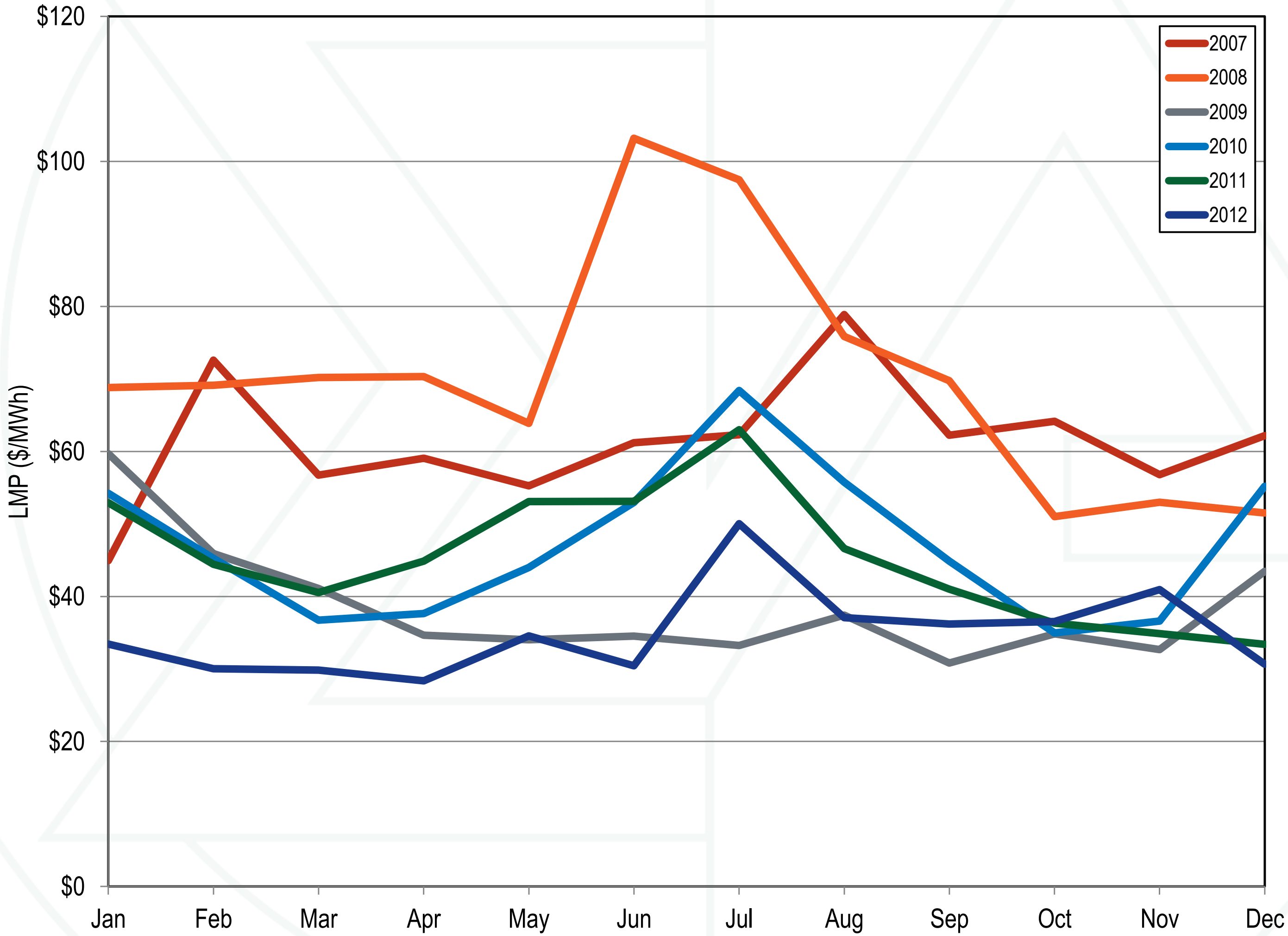


Figure 2-17 Spot average fuel price comparison: 2011 and 2012 ($/MMBtu)

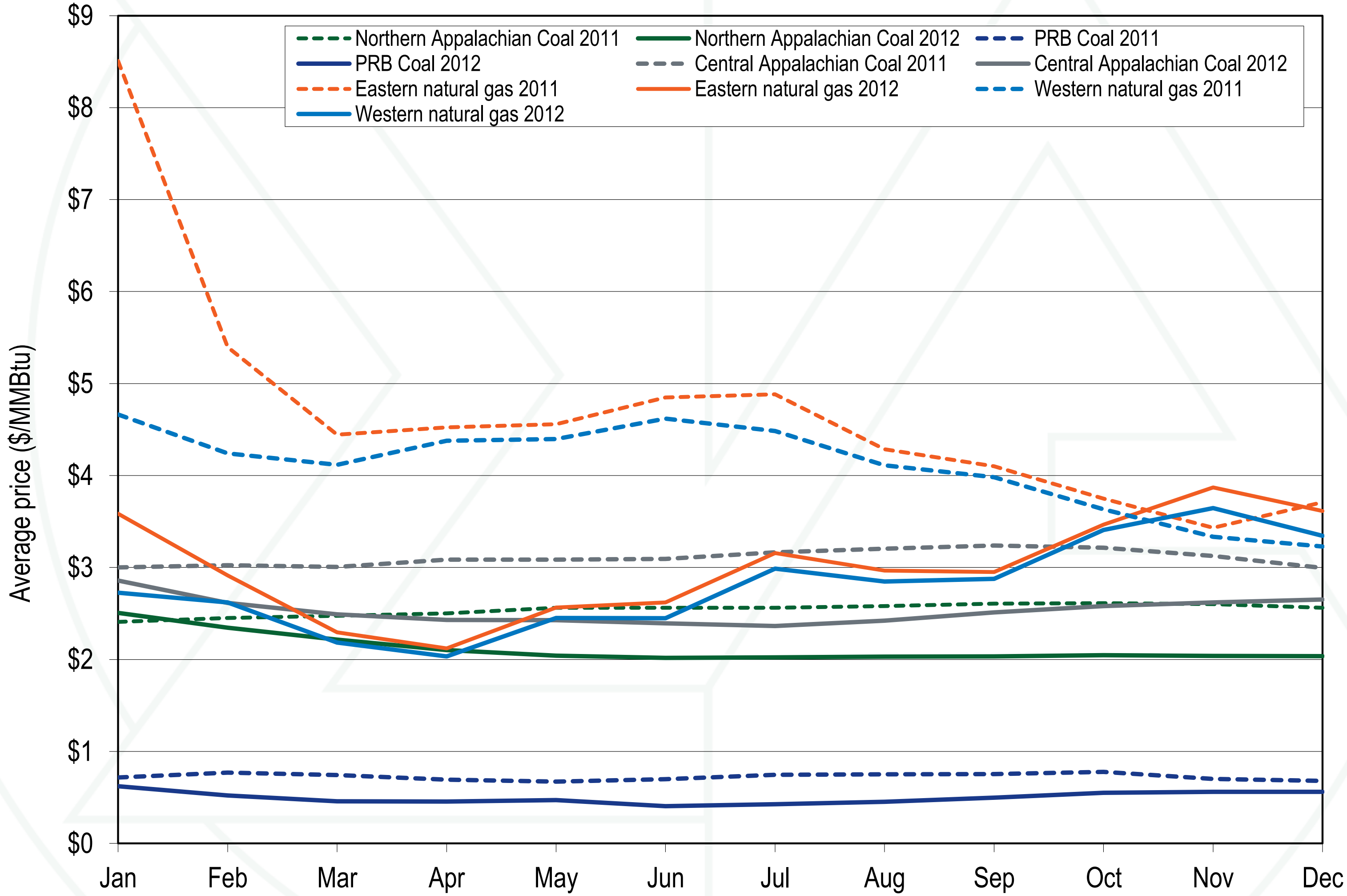


Figure 2-18 Average spot fuel cost of generation of CP, CT, and CC: 2011 and 2012

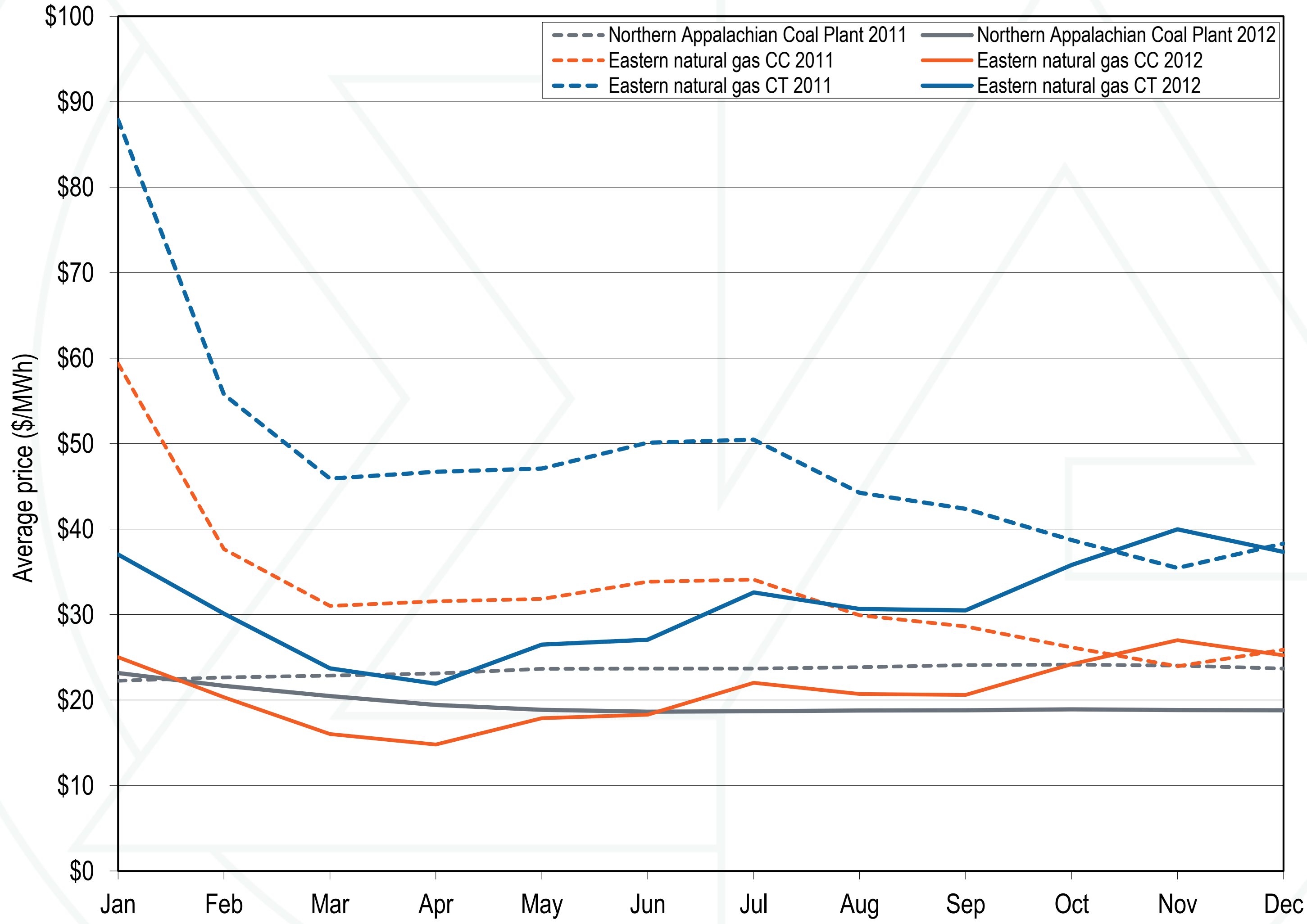


Table 2-39 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2012 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.23	$41.17	16.9%
	2011 Load-Weighted LMP	**2012 Fuel-Cost-Adjusted, Load-Weighted LMP**	**Change**
Average	$45.94	$41.17	(10.4%)
	2011 Load-Weighted LMP	**2012 Load-Weighted LMP**	**Change**
Average	$45.94	$35.23	(23.3%)

Table 2-2 PJM generation (By fuel source (GWh)): 2011 and 2012

		2011 GWh	Percent	2012 GWh	Percent	Change in Output
Coal		359,410.4	47.1%	332,762.0	42.1%	(7.4%)
	Standard Coal	347,940.4	45.6%	323,043.5	40.9%	(6.9%)
	Waste Coal	11,470.0	1.5%	9,718.5	1.2%	(0.5%)
Nuclear		262,968.3	34.5%	273,372.2	34.6%	4.0%
Gas		106,853.3	14.0%	148,230.4	18.8%	38.7%
	Natural Gas	105,049.7	13.8%	146,007.5	18.5%	39.0%
	Landfill Gas	1,803.2	0.2%	2,222.3	0.3%	23.2%
	Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric		14,729.2	1.9%	12,649.7	1.6%	(14.1%)
Wind		11,037.0	1.4%	12,633.6	1.6%	14.5%
Waste		5,200.2	0.7%	5,177.6	0.7%	(0.4%)
	Solid Waste	4,083.5	0.5%	4,200.3	0.5%	2.9%
	Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil		2,271.5	0.3%	5,030.9	0.6%	121.5%
	Heavy Oil	1,885.4	0.2%	4,796.9	0.6%	154.4%
	Light Oil	356.6	0.0%	218.9	0.0%	(38.6%)
	Diesel	16.8	0.0%	9.9	0.0%	(40.9%)
	Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
	Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar		56.0	0.0%	233.5	0.0%	317.3%
Battery		0.2	0.0%	0.3	0.0%	36.9%
Total		762,526.0	100.0%	790,090.3	100.0%	3.6%

Table 2-3 PJM Generation (By fuel source (GWh)): 2011 and 2012; excluding ATSI and DEOK zones

	2011 GWh	Percent	2012 GWh	Percent	Change in Output
Coal	359,410.4	47.1%	290,845.1	39.7%	(19.1%)
Standard Coal	347,940.4	45.6%	281,126.7	38.4%	(18.6%)
Waste Coal	11,470.0	1.5%	9,718.5	1.3%	(0.5%)
Nuclear	262,968.3	34.5%	260,508.9	35.6%	(0.9%)
Gas	106,853.3	14.0%	144,809.5	19.8%	35.5%
Natural Gas	105,049.7	13.8%	142,730.3	19.5%	35.9%
Landfill Gas	1,803.2	0.2%	2,078.7	0.3%	15.3%
Biomass Gas	0.3	0.0%	0.5	0.0%	61.0%
Hydroelectric	14,729.2	1.9%	12,649.7	1.7%	(14.1%)
Wind	11,037.0	1.4%	12,633.6	1.7%	14.5%
Waste	5,200.2	0.7%	5,177.6	0.7%	(0.4%)
Solid Waste	4,083.5	0.5%	4,200.3	0.6%	2.9%
Miscellaneous	1,116.6	0.1%	977.3	0.1%	(12.5%)
Oil	2,271.5	0.3%	5,025.6	0.7%	121.2%
Heavy Oil	1,885.4	0.2%	4,796.9	0.7%	154.4%
Light Oil	356.6	0.0%	215.3	0.0%	(39.6%)
Diesel	16.8	0.0%	8.2	0.0%	(50.9%)
Kerosene	12.8	0.0%	5.1	0.0%	(59.7%)
Jet Oil	0.1	0.0%	0.0	0.0%	(31.7%)
Solar	56.0	0.0%	233.5	0.0%	317.3%
Battery	0.2	0.0%	0.3	0.0%	36.9%
Total	762,526.0	100.0%	731,883.9	100.0%	(4.0%)

Table 2-10 Offer-capping statistics: 2008 to 2012

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012	1.2%	0.8%	0.6%	0.4%

Table 2-40 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$18.94	53.8%	$19.40	42.2%
Gas	$8.38	23.8%	$18.86	41.0%
Ten Percent Addder	$3.49	9.9%	$4.71	10.2%
VOM	$2.53	7.2%	$2.50	5.4%
Oil	$1.69	4.8%	$1.48	3.2%
NA	$1.17	3.3%	$1.99	4.3%
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.12	0.3%
NO_x Cost	$0.10	0.3%	$0.30	0.6%
CO_2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO_2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Markup	($1.38)	(3.9%)	($4.35)	(9.5%)
Total	$35.23	100.0%	$45.94	100.0%

Table 2-41 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2012 and 2011

	2012		2011	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$19.11	54.2%	$19.51	42.5%
Gas	$8.38	23.8%	$18.80	40.9%
VOM	$2.54	7.2%	$2.51	5.5%
Oil	$1.69	4.8%	$1.48	3.2%
Ten Percent Addder	$1.50	4.2%	$2.55	5.6%
NA	$1.17	3.3%	$2.15	4.7%
Markup	$0.43	1.2%	($2.42)	(5.3%)
LPA Rounding Difference	$0.32	0.9%	($0.05)	(0.1%)
Increase Generation Adder	$0.12	0.3%	$0.21	0.5%
FMU Adder	$0.10	0.3%	$0.11	0.2%
NO_x Cost	$0.10	0.3%	$0.30	0.6%
CO_2 Cost	$0.09	0.3%	$0.29	0.6%
Market-to-Market Adder	$0.02	0.1%	($0.07)	(0.1%)
SO_2 Cost	$0.02	0.1%	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%	$0.01	0.0%
Other	$0.01	0.0%	$0.01	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Wind	($0.04)	(0.1%)	($0.05)	(0.1%)
LPA-SCED Differential	($0.12)	(0.3%)	$0.82	1.8%
Decrease Generation Adder	($0.21)	(0.6%)	($0.25)	(0.5%)
Total	$35.23	100.0%	$45.94	100.0%

Table 2-18 Average, real-time marginal unit markup index (By price category): 2012 and 2011

	2012			2011		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	29.0%	(0.10)	($3.89)	12.1%
$25 to $50	(0.05)	($2.67)	52.3%	(0.07)	($6.58)	68.7%
$50 to $75	0.05	$1.23	4.5%	(0.02)	($6.05)	8.3%
$75 to $100	0.28	$24.25	0.6%	0.12	$6.80	1.6%
$100 to $125	0.23	$23.66	0.5%	0.25	$25.53	0.7%
$125 to $150	0.20	$27.69	0.2%	0.25	$33.72	0.4%
>= $150	0.04	$9.47	5.5%	0.12	$24.73	4.1%

Table 10-14 Total PJM congestion (Dollars (Millions)): 2008 to 2012

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$26,979.0	7.6%
2009	$719.0	(65.0%)	$19,927.0	3.6%
2010	$1,423.3	98.0%	$26,249.0	5.4%
2011	$999.0	(29.8%)	$28,836.0	3.5%
2012	$529.0	(47.0%)	$29,181.0	1.8%

Figure 10-1 PJM monthly congestion (Dollars (Millions)): 2008 to 2012

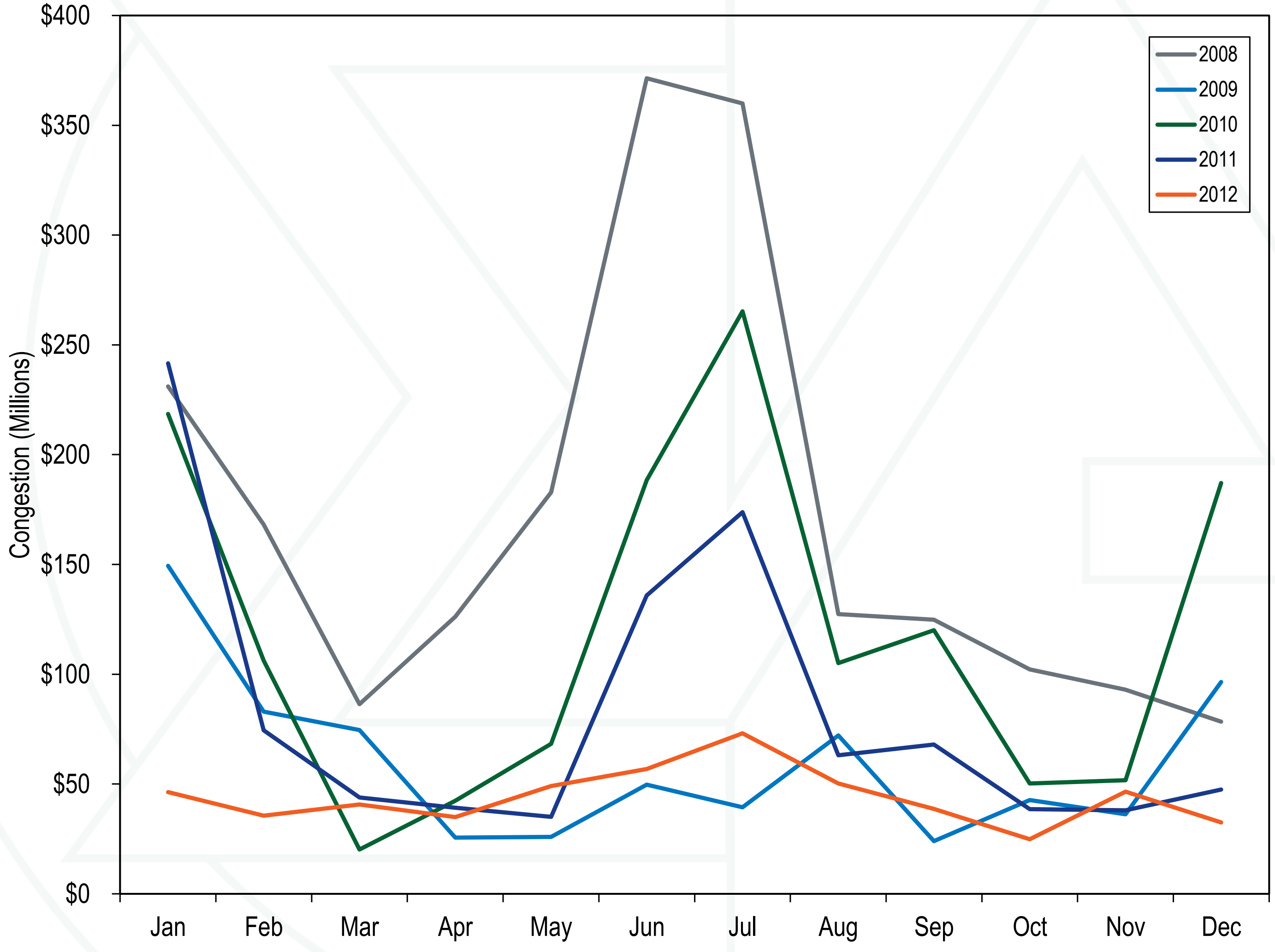


Table 10-15 Total PJM congestion costs by category (Dollars (Millions)): 2011 to 2012

	Congestion Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2011	$112.2	($1,009.9)	($123.1)	$0.0	$999.0
2012	$138.5	($444.0)	($53.5)	$0.0	$529.0

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2012

	1-Jan-12		31-May-12		1-Jun-12		31-Dec-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	79,311.0	42.8%	79,664.6	42.9%	75,989.2	41.8%
Gas	49,769.3	27.8%	51,180.1	27.6%	51,949.1	28.0%	52,003.2	28.6%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	7,879.8	4.2%	7,879.8	4.3%
Nuclear	32,492.6	18.2%	33,085.0	17.9%	33,149.5	17.8%	33,024.0	18.1%
Oil	11,977.3	6.7%	12,260.4	6.6%	11,532.9	6.2%	11,531.2	6.3%
Solar	15.3	0.0%	16.3	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	705.1	0.4%	689.1	0.4%	736.1	0.4%	736.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	779.6	0.4%	779.6	0.4%
Total	178,854.1	100.0%	185,249.0	100.0%	185,738.6	100.0%	181,990.1	100.0%

Figure 4-5 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2012

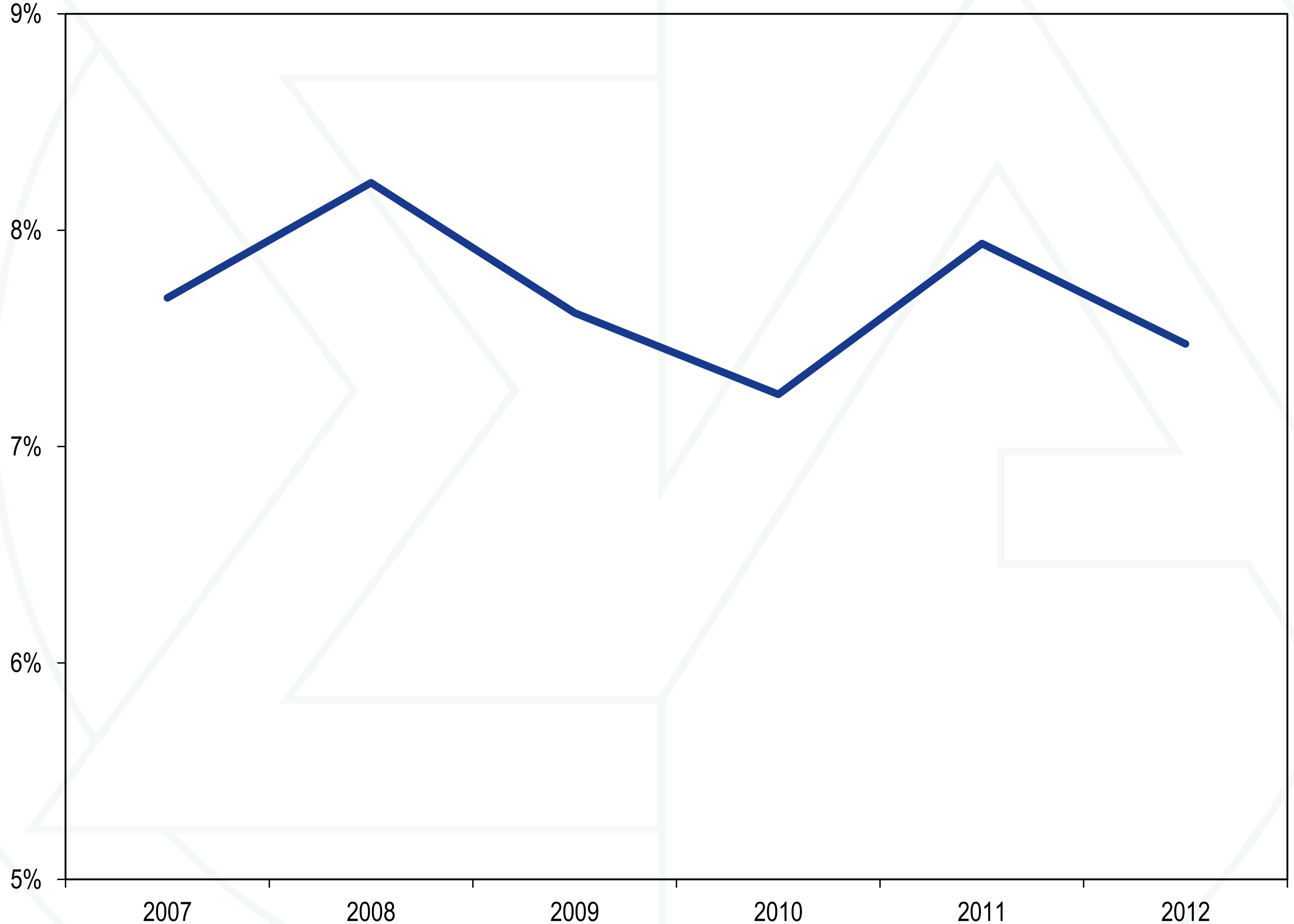


Table 4-35 PJM EFORd, XEFORd and EFORp data by unit type: 2012

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	4.2%	3.3%	2.0%	0.9%	2.2%
Combustion Turbine	8.2%	5.7%	2.9%	2.5%	5.3%
Diesel	5.6%	5.0%	2.8%	0.6%	2.8%
Hydroelectric	4.4%	4.2%	4.9%	0.2%	(0.5%)
Nuclear	1.6%	1.5%	1.8%	0.1%	(0.2%)
Steam	10.6%	9.7%	5.7%	0.9%	4.9%
Total	7.5%	6.5%	4.0%	1.0%	3.5%

Figure 4-6 PJM 2012 distribution of EFORd data by unit type

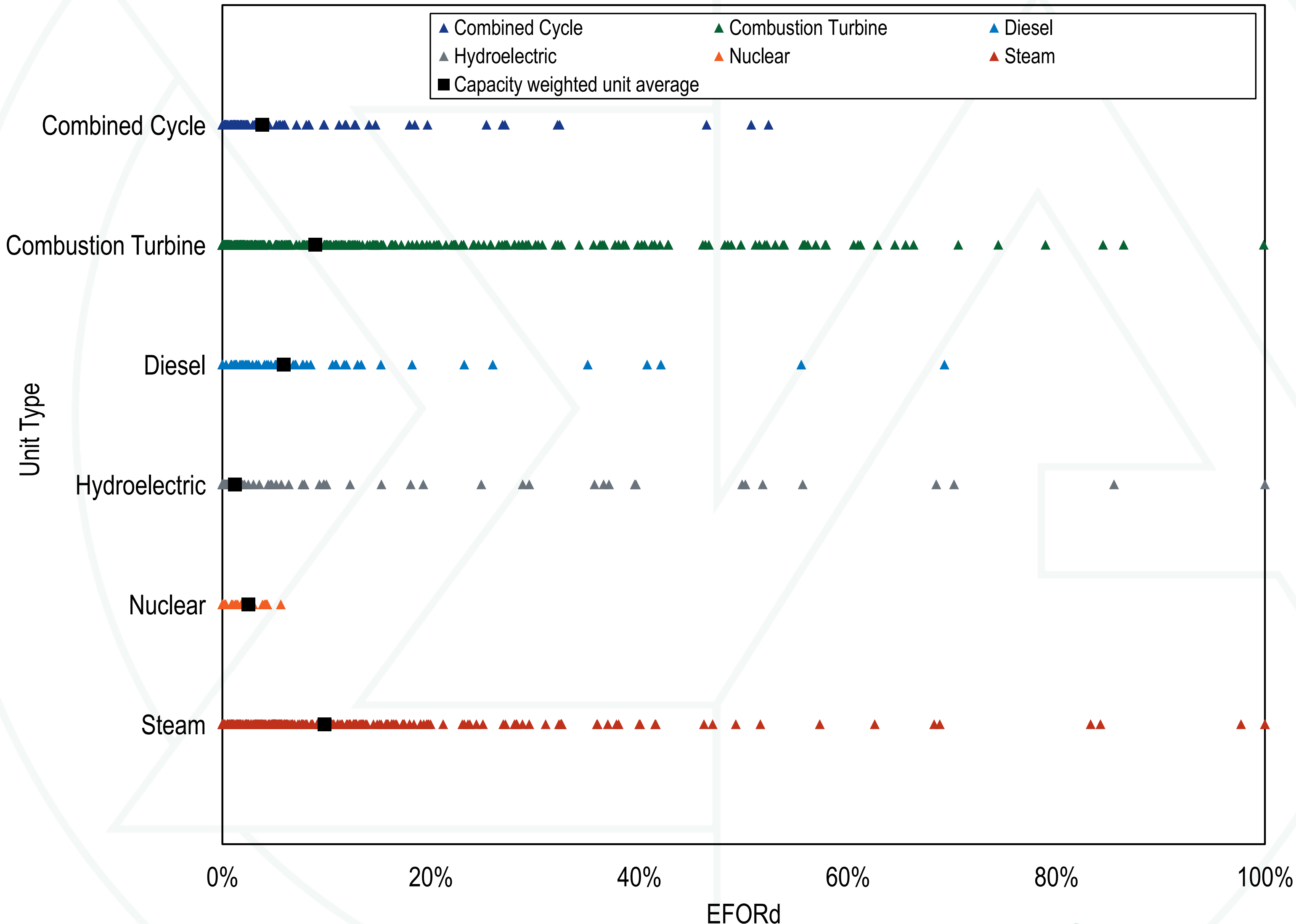


Figure 4-3 History of capacity prices: Calendar year 1999 through 2015

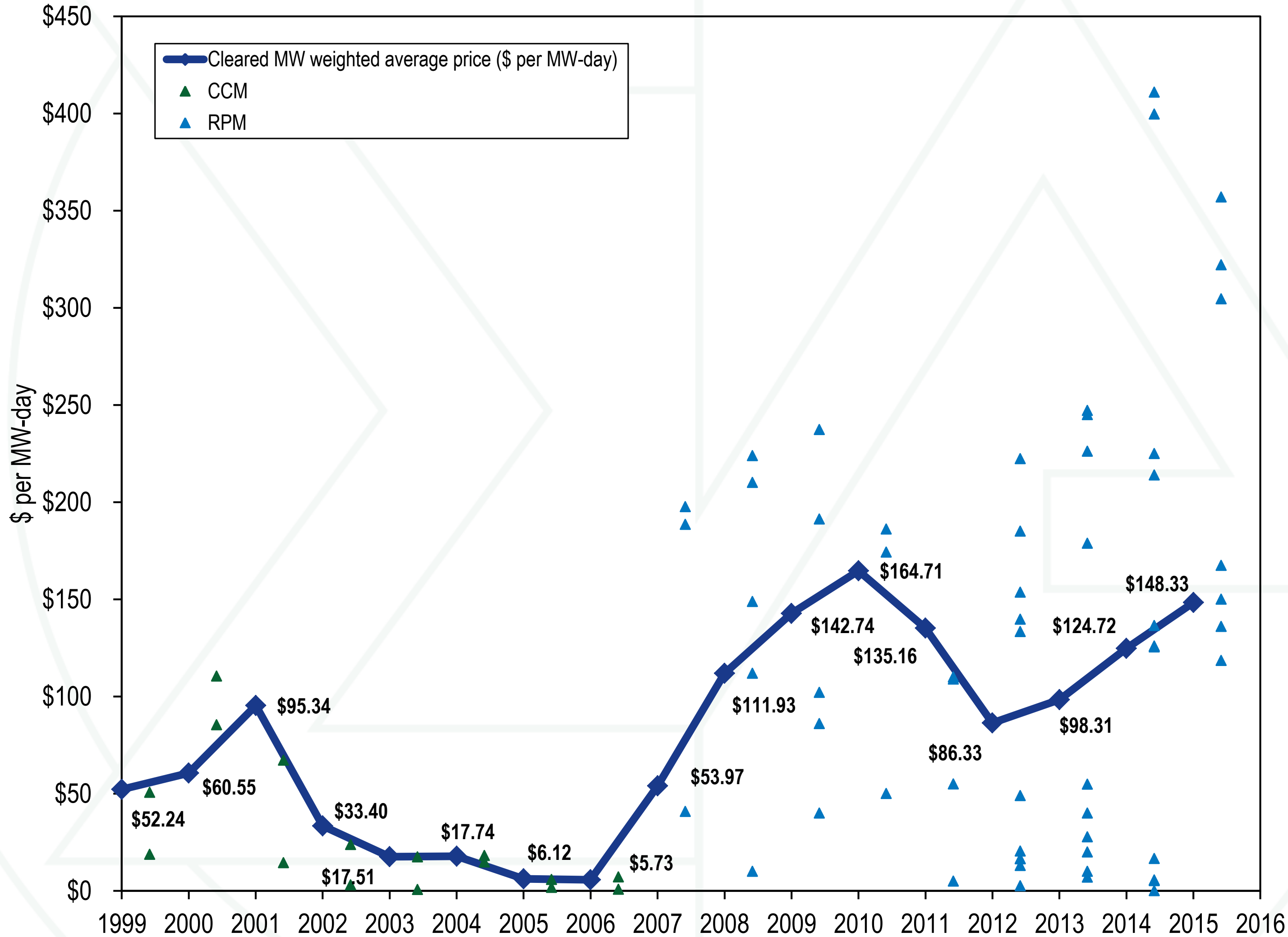


Figure 6-3 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012

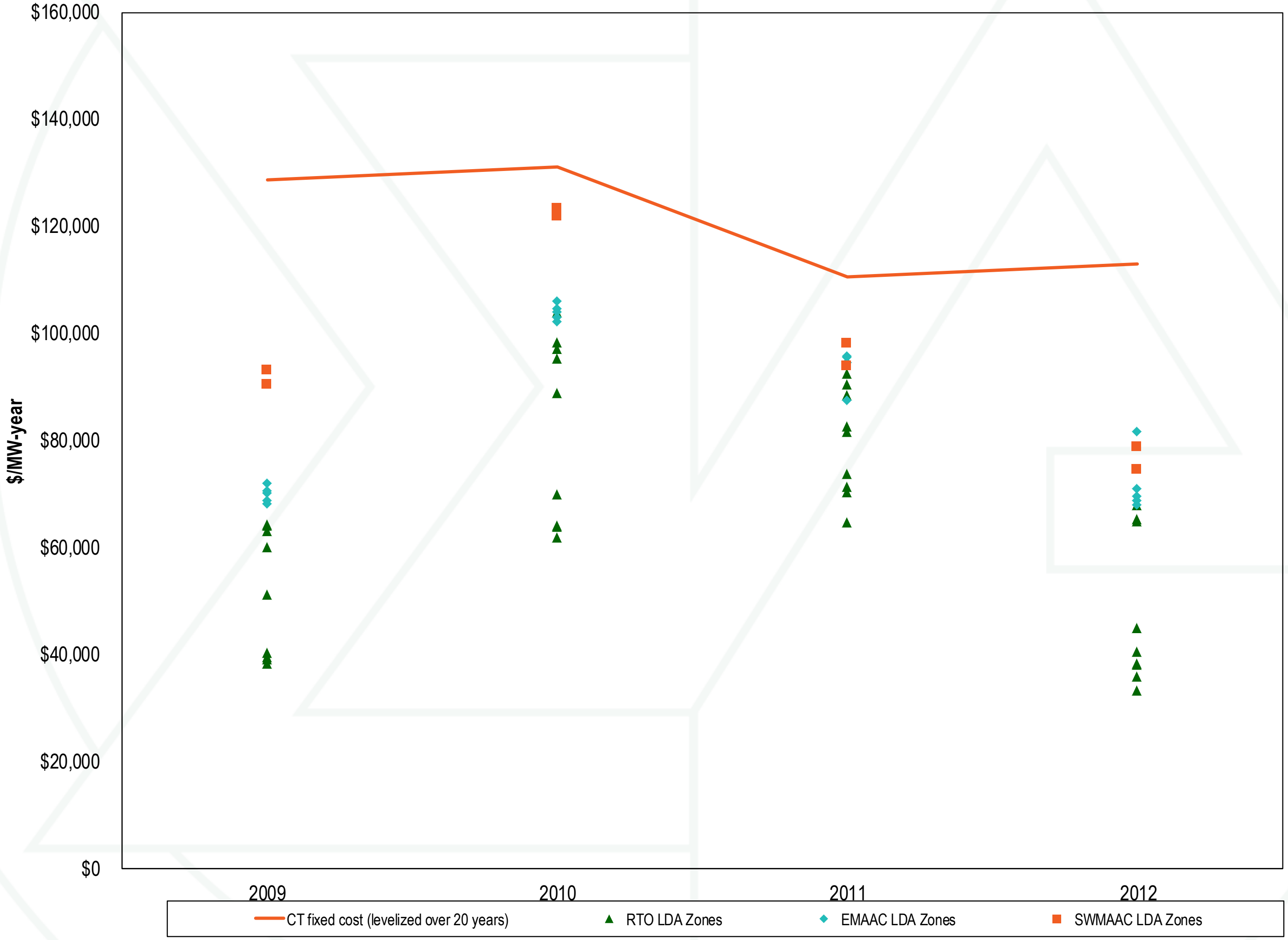


Figure 6-5 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012

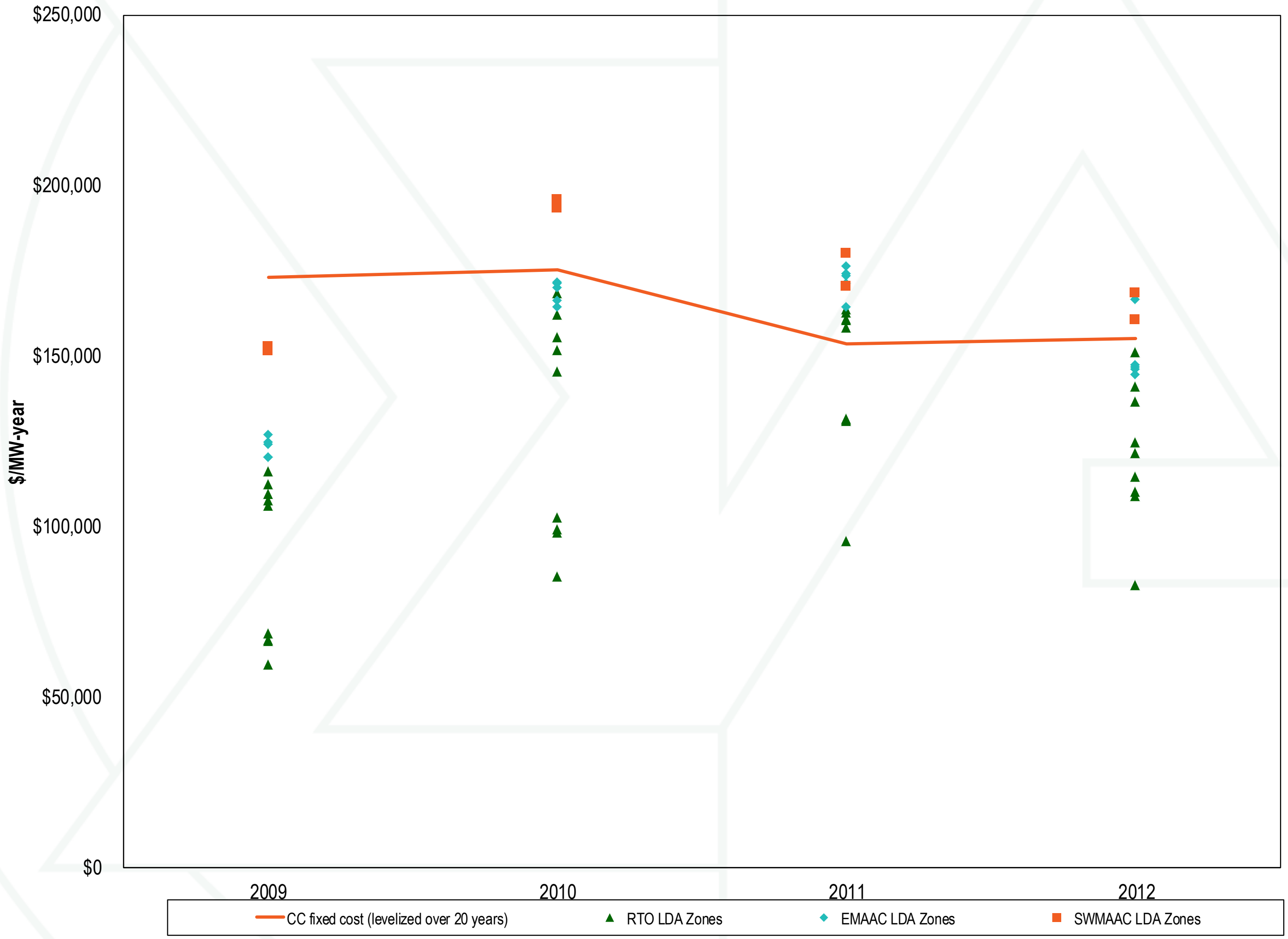
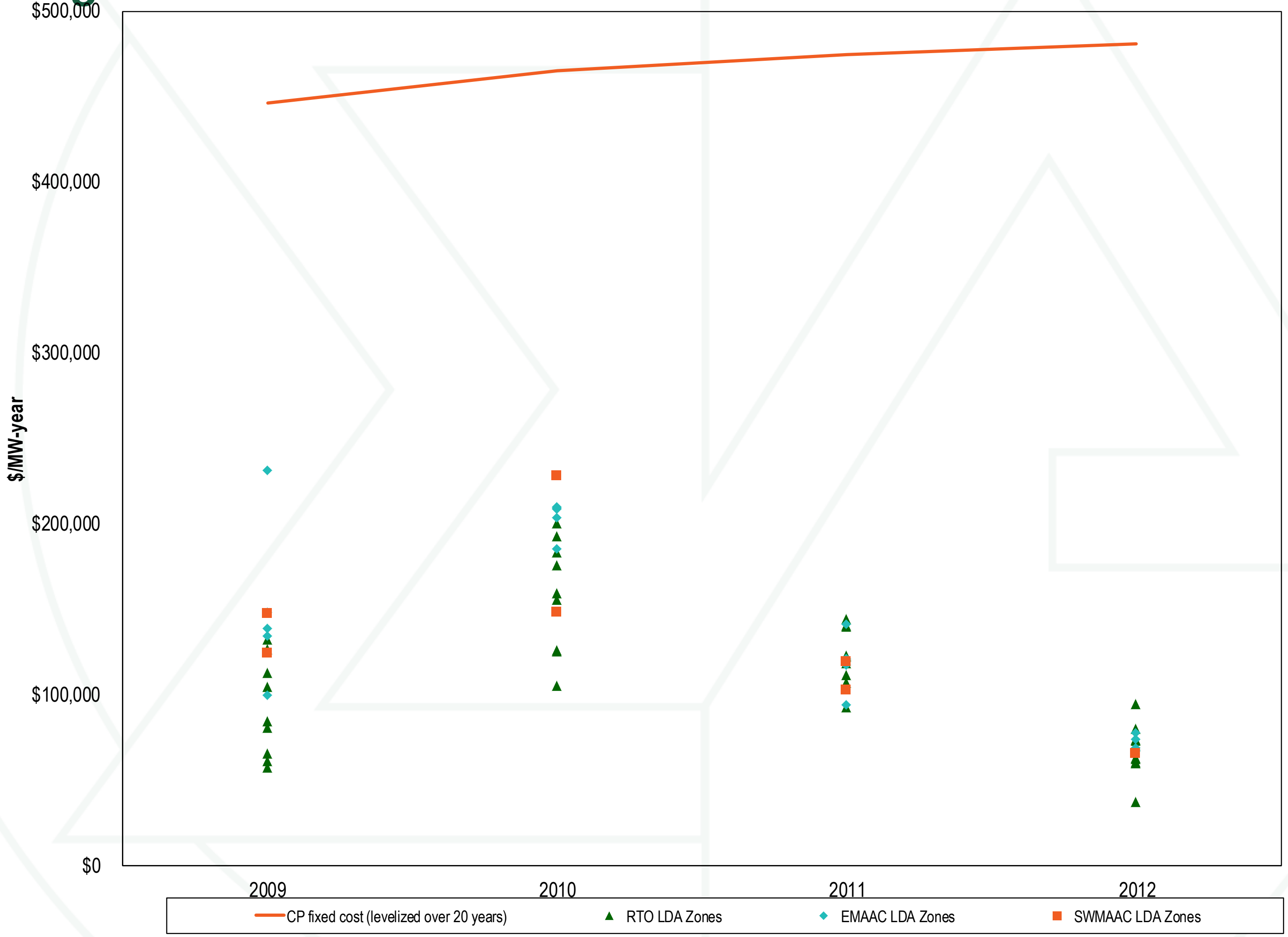


Figure 6-7 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2012



Monitoring Analytics

Table 6-19 Percent of 20-year levelized fixed costs recovered by IGCC energy and capacity net revenue

Zone	2012
Dominion	5%

Table 6-20 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2012
AEP	28%

Table 6-21 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012
ComEd	65%
PENELEC	68%

Table 6-22 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012
PSEG	97%

Table 6-33 Proportion of units recovering avoidable costs from energy and ancillary markets for 2009 to 2012

	Units with full recovery from energy and ancillary services markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	39%	71%	61%	67%
CC - Two of Three on One Frame F Technology	63%	76%	90%	86%
CT - First & Second Generation Aero (P&W FT 4)	8%	5%	7%	6%
CT - First & Second Generation Frame B	3%	11%	19%	18%
CT - Second Generation Frame E	21%	48%	63%	73%
CT - Third Generation Aero	17%	36%	72%	68%
CT - Third Generation Frame F	18%	39%	59%	77%
Diesel	64%	59%	56%	44%
Hydro	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	28%	42%	43%	36%
Pumped Storage	70%	90%	70%	90%
Sub-Critical Coal	76%	82%	70%	50%
Super Critical Coal	86%	94%	92%	61%

Table 6-34 Proportion of units recovering avoidable costs from all markets for 2009 to 2012

	Units with full recovery from all markets			
Technology	2009	2010	2011	2012
CC - NUG Cogeneration Frame B or E Technology	87%	88%	89%	79%
CC - Two of Three on One Frame F Technology	92%	100%	100%	97%
CT - First & Second Generation Aero (P&W FT 4)	99%	99%	100%	100%
CT - First & Second Generation Frame B	99%	98%	92%	90%
CT - Second Generation Frame E	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	94%
CT - Third Generation Frame F	95%	96%	98%	96%
Diesel	95%	97%	91%	85%
Hydro	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%
Oil or Gas Steam	93%	88%	88%	73%
Pumped Storage	100%	100%	100%	100%
Sub-Critical Coal	88%	93%	87%	61%
Super Critical Coal	97%	100%	96%	85%

Table 6-35 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	3,725	35,013
Avg. Installed Capacity (ICAP)	248	347
Avg. Age of Plant (Years)	46	36
Avg. Heat Rate (Btu/kWh)	10,999	10,564
Avg. Run Hours (Hours)	3,348	6,054
Avg. Avoidable Costs ($/MW-year)	167	149

Table 6-36 Installed capacity associated with levels of avoidable cost recovery: 2012

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	1,111	3%
65% - 75%	555	1%
75% - 90%	531	1%
90% - 100%	1,528	4%
> 100%	35,013	90%
Total	38,737	100%

Table 11-11 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,322.3
Retirements 2012	6,961.9
Retirements 2013	169.0
Planned Retirements 2013	237.4
Planned Retirements Post-2013	12,834.3
Total	21,524.9

Table 11-14 Unit deactivations: January 2012 through January 1, 2013

Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Sporn 5	440.0	Coal	AEP	51	Feb 13, 2012
State Line 3	197.0	Coal	ComEd	56	Mar 25, 2012
State Line 4	318.0	Coal	ComEd	51	Mar 25, 2012
Viking Energy NUG	16.0	Wood Waste	PPL	24	Mar 31, 2012
Walter C Beckjord 1	94.0	Coal	DEOK	59	May 01, 2012
Buzzard Point East Banks 1, 2, 4-8	112.0	Light Oil	Pepco	44	May 31, 2012
Buzzard Point West Banks 1-9	128.0	Light Oil	Pepco	44	May 31, 2012
Eddystone 2	309.0	Coal	PECO	51	May 31, 2012
Niles 2	108.0	Coal	ATSI	58	Jun 01, 2012
Elrama 1	93.0	Coal	DLCO	60	Jun 01, 2012
Elrama 2	93.0	Coal	DLCO	59	Jun 01, 2012
Elrama 3	103.0	Coal	DLCO	57	Jun 01, 2012
Kearny 10	122.0	Natural Gas	PSEG	42	Jun 01, 2012
Kearny 11	128.0	Natural Gas	PSEG	42	Jun 01, 2012
Benning 15	275.0	Light Oil	Pepco	44	Jul 17, 2012
Benning 16	273.0	Light Oil	Pepco	40	Jul 17, 2012
Crawford 8	319.0	Coal	ComEd	51	Aug 24, 2012
Crawford 7	213.0	Coal	ComEd	54	Aug 28, 2012
Fisk Street 19	326.0	Coal	ComEd	53	Aug 30, 2012
Albright 1	73.0	Coal	APS	59	Sep 01, 2012
Albright 2	73.0	Coal	APS	59	Sep 01, 2012
Albright 3	137.0	Coal	APS	57	Sep 01, 2012
Armstrong 1	172.0	Coal	APS	54	Sep 01, 2012
Armstrong 2	171.0	Coal	APS	55	Sep 01, 2012
R Paul Smith 3	28.0	Coal	APS	64	Sep 01, 2012
R Paul Smith 4	87.0	Coal	APS	53	Sep 01, 2012
Rivesville 5	35.0	Coal	APS	69	Sep 01, 2012
Rivesville 6	86.0	Coal	APS	61	Sep 01, 2012
Willow Island 1	53.0	Coal	APS	63	Sep 01, 2012
Willow Island 2	164.0	Coal	APS	51	Sep 01, 2012
Bay Shore 2	120.0	Coal	ATSI	53	Sep 01, 2012
Bay Shore 3	119.0	Coal	ATSI	49	Sep 01, 2012
Bay Shore 4	180.0	Coal	ATSI	44	Sep 01, 2012
Eastlake 4	225.0	Coal	ATSI	56	Sep 01, 2012
Eastlake 5	597.0	Coal	ATSI	40	Sep 01, 2012
Howard Down 10	23.0	Coal	AECO	42	Sep 01, 2012
Niles 1	109.0	Coal	ATSI	58	Oct 01, 2012
Elrama 4	171.0	Coal	DLCO	51	Oct 01, 2012
Potomac River 1	88.0	Coal	Pepco	63	Oct 01, 2012
Potomac River 2	88.0	Coal	Pepco	62	Oct 01, 2012
Potomac River 3	102.0	Coal	Pepco	58	Oct 01, 2012
Potomac River 4	102.0	Coal	Pepco	56	Oct 01, 2012
Potomac River 5	102.0	Coal	Pepco	55	Oct 01, 2012
SMART Paper	24.9	Coal	DEOK	88	Oct 10, 2012
Conesville 3	165.0	Coal	AEP	50	Dec 31, 2012
Schuylkill 1	166.0	Heavy Oil	PECO	54	Jan 01, 2013
Schuylkill Diesel	3.0	Diesel	PECO	45	Jan 01, 2013

Table 11-12 Planned deactivations of PJM units after 2012, as of March 1, 2013

Unit	Zone	MW	Projected Deactivation Date
Warren County Landfill	JCPL	2.9	09-Jan-13
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
Riverside 6	BGE	115.0	01-Jun-14
Burlington 9	PSEG	184.0	01-Jun-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1-2	Dominion	323.0	31-Dec-14
Portland	Met-Ed	401.0	07-Jan-15
Beckjord 2-6	DEOK	1,024.0	01-Apr-15
Avon Lake	ATSI	732.0	16-Apr-15
New Castle	ATSI	330.5	16-Apr-15
Titus	Met-Ed	243.0	16-Apr-15
Shawville	PENELEC	597.0	16-Apr-15
Gilbert 1-4, 8	JCPL	188.0	01-May-15
Glen Gardner	JCPL	160.0	01-May-15
Werner 1-4	JCPL	212.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Middle 1-3	AECO	74.7	31-May-15
Missouri Ave B, C, D	AECO	60.0	31-May-15
Essex 12	PSEG	184.0	31-May-15
Big Sandy 2	AEP	278.0	01-Jun-15
Clinch River 3	AEP	230.0	01-Jun-15
Glen Lyn 5-6	AEP	325.0	01-Jun-15
Kammer	AEP	600.0	01-Jun-15
Kanawha River	AEP	400.0	01-Jun-15
Muskingum River 1-4	AEP	790.0	01-Jun-15
Picway 5	AEP	95.0	01-Jun-15
Sporn	AEP	580.0	01-Jun-15
Tanners Creek 1-3	AEP	488.1	01-Jun-15
Ashtabula	ATSI	210.0	01-Jun-15
Eastlake 1-3	ATSI	327.0	01-Jun-15
Lake Shore	ATSI	190.0	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8, 11	PSEG	205.0	01-Jun-15
Edison 1-3	PSEG	504.0	01-Jun-15
Essex 10-11	PSEG	352.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 1-4, 6	PSEG	558.0	01-Jun-15
BL England Diesels	AECO	8.0	01-Oct-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		13,071.7	

Table 11-13 HEDD Units in PJM as of January 1, 2013

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Figure 11-1 Unit retirements in PJM: 2012 through 2019

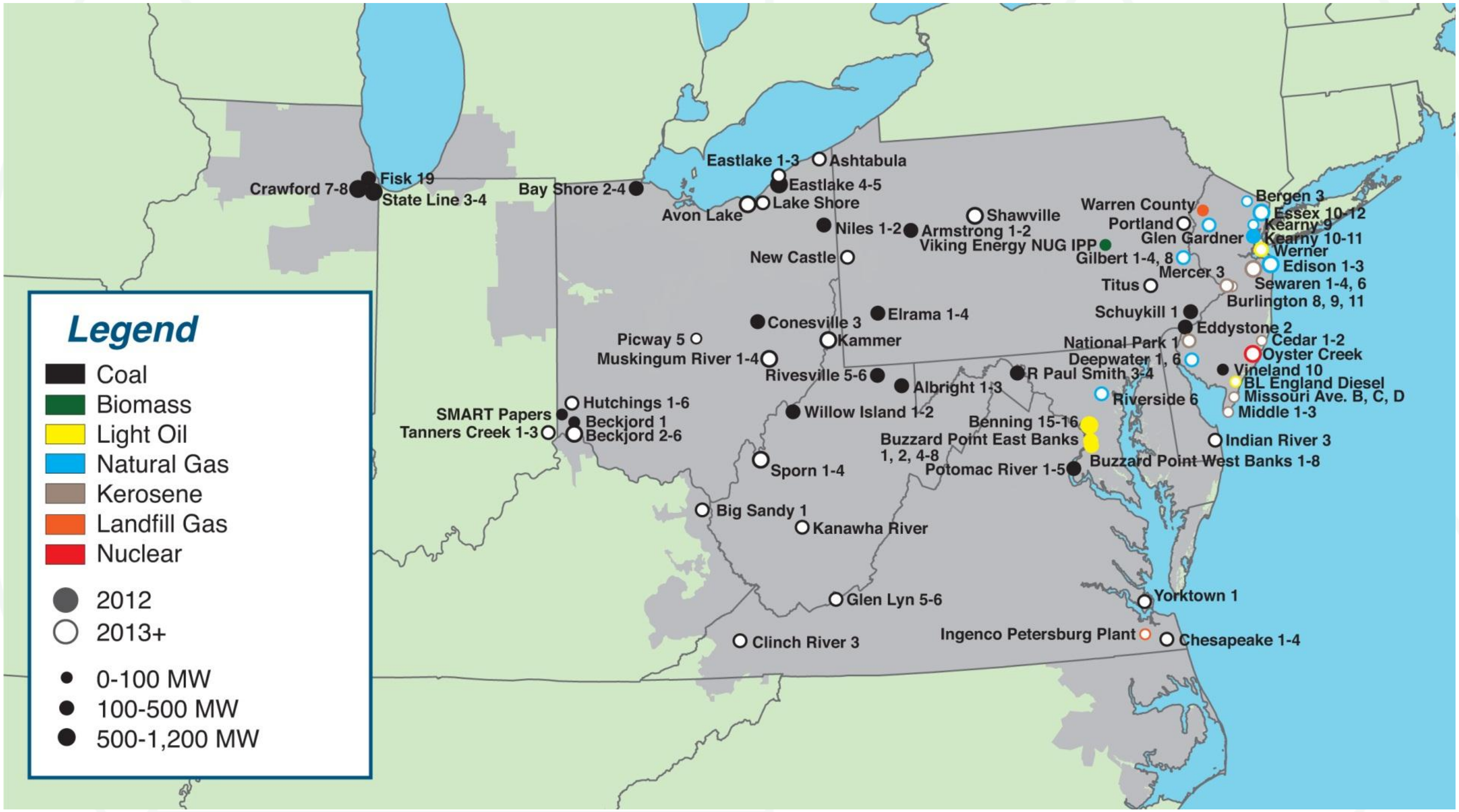


Table 3-1 Day-ahead and balancing operating reserve credits and charges

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
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
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation				
Lost Opportunity Cost	Balancing Operating Reserve Lost Opportunity Cost				
Real-Time Import Transactions	Balancing Operating Reserve Transaction	→	Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	in RTO Region
Resources Performing Annual Scheduled Black Start Tests	Balancing Operating Reserve Generator				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Real-Time Deviations from Day-Ahead Schedule by RTO, Eastern or	in RTO, Eastern/Western Region

Table 3-6 Total operating reserve charges: 1999 through 2012

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing
1999	$133,897,428	NA	7.5%
2000	$216,985,147	62.1%	9.6%
2001	$284,046,709	30.9%	8.5%
2002	$273,718,553	(3.6%)	5.8%
2003	$376,491,514	37.5%	5.4%
2004	$537,587,821	42.8%	6.2%
2005	$712,601,789	32.6%	3.1%
2006	$365,572,034	(48.7%)	1.7%
2007	$503,279,869	37.7%	1.6%
2008	$474,268,500	(5.8%)	1.4%
2009	$322,729,996	(32.0%)	1.2%
2010	$622,843,365	93.0%	1.8%
2011	$603,164,922	(3.2%)	1.7%
2012	$648,728,097	7.6%	2.2%

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): 2011 and 2012

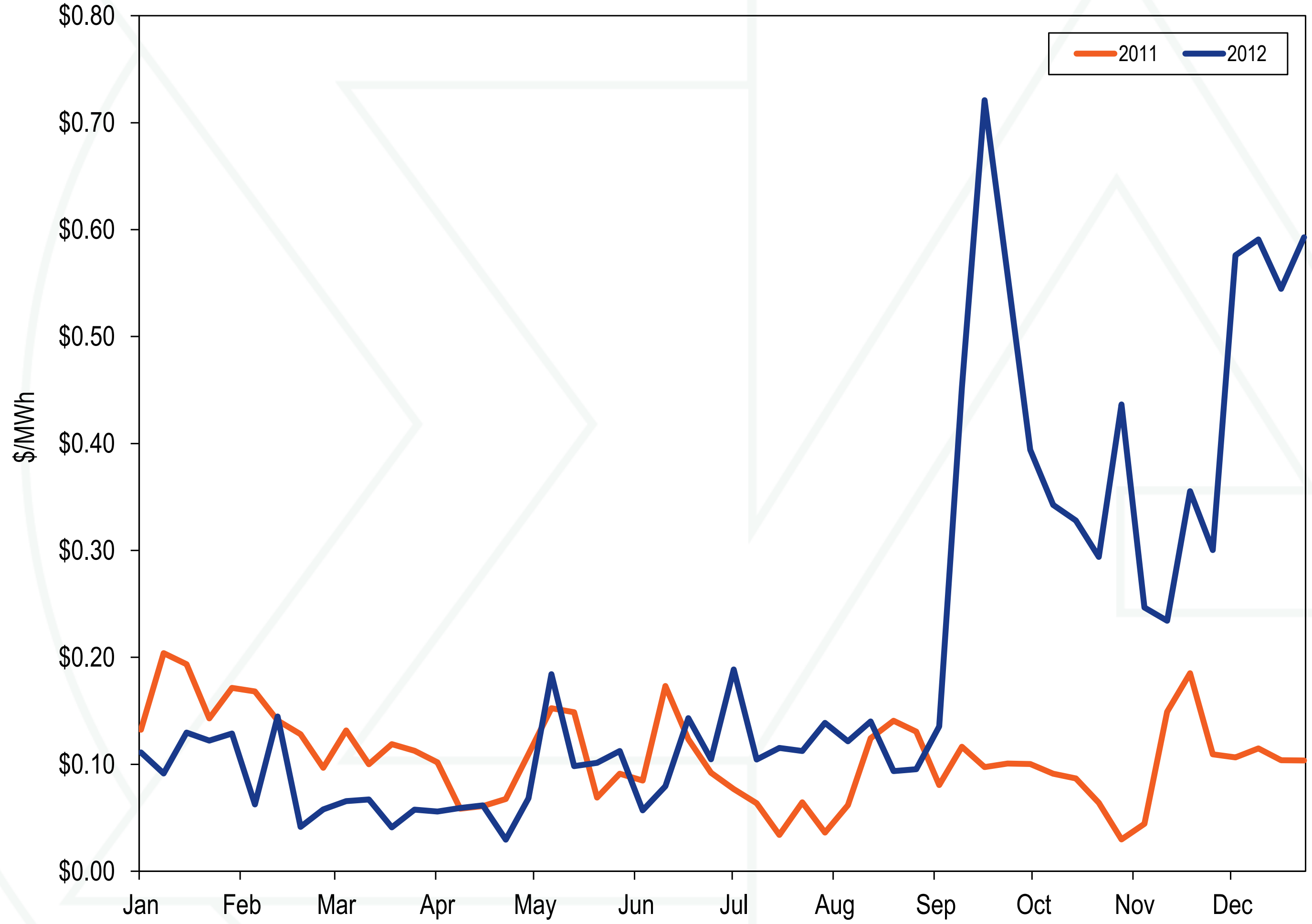


Table 3-14 Operating reserve rates ($/MWh): 2011 and 2012

Rate	2011 ($/MWh)	2012 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1068	0.2001	0.0933	87.4%
RTO Reliability	0.0681	0.0245	(0.0436)	(64.0%)
East Reliability	0.0274	0.0219	(0.0055)	(20.2%)
West Reliability	0.0775	0.1154	0.0379	48.9%
RTO Deviation	0.9466	0.8147	(0.1319)	(13.9%)
East Deviation	0.4233	0.3332	(0.0901)	(21.3%)
West Deviation	0.1106	0.1265	0.0159	14.4%
Lost Opportunity Cost	1.0693	1.3223	0.2529	23.7%
Canceled Resources	0.0621	0.0235	(0.0386)	(62.2%)

Table 3-29 Top 10 operating reserve credits units (By percent of total system): 2001 through 2012

	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%	0.6%

Table 5-1 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	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. ILR program ended with 2012/2013 DY.	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 5-1 Demand Response revenue by market: 2002 through 2012

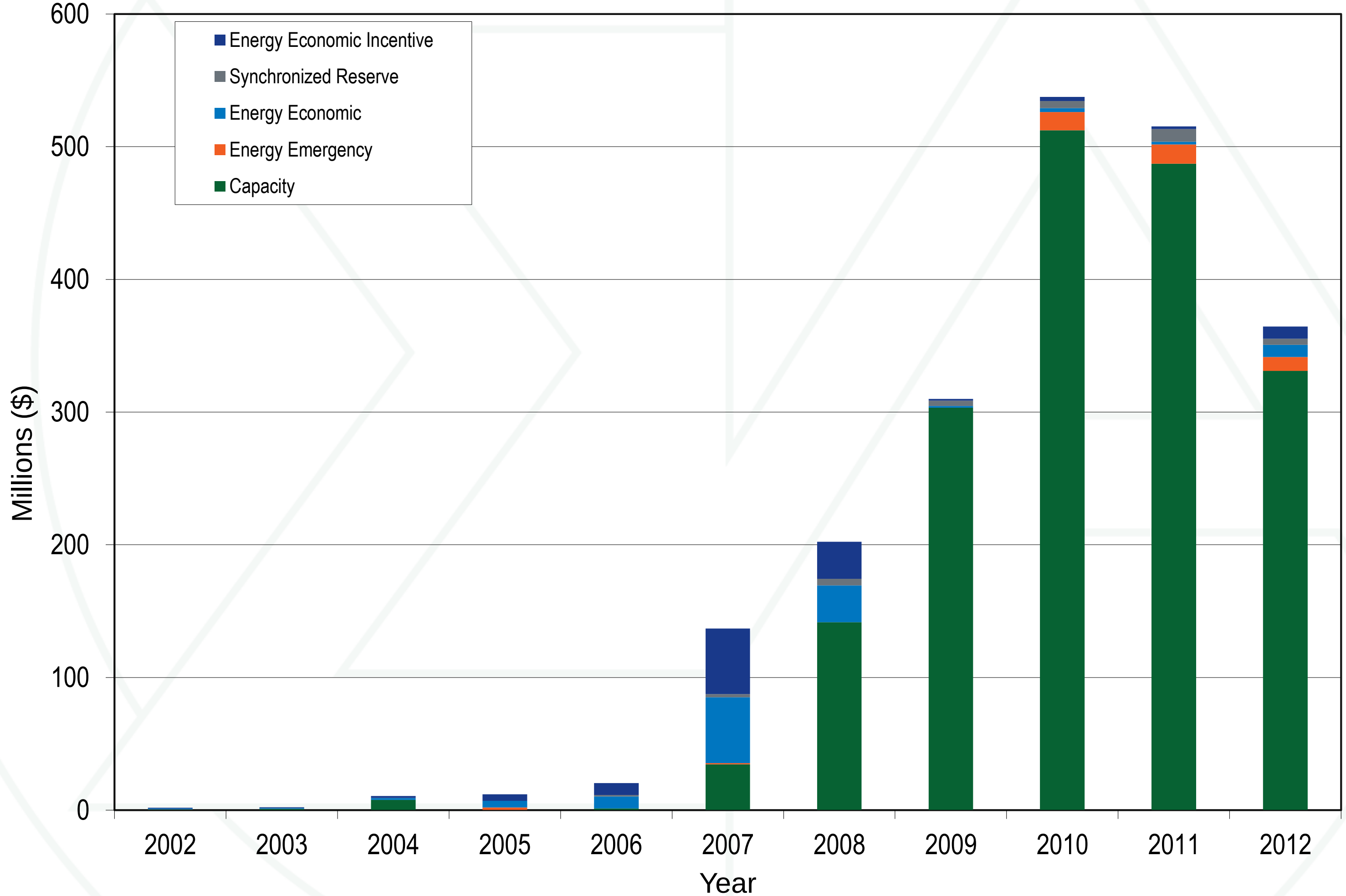


Figure 5-2 Economic Program payments by month: 2007 through 2012

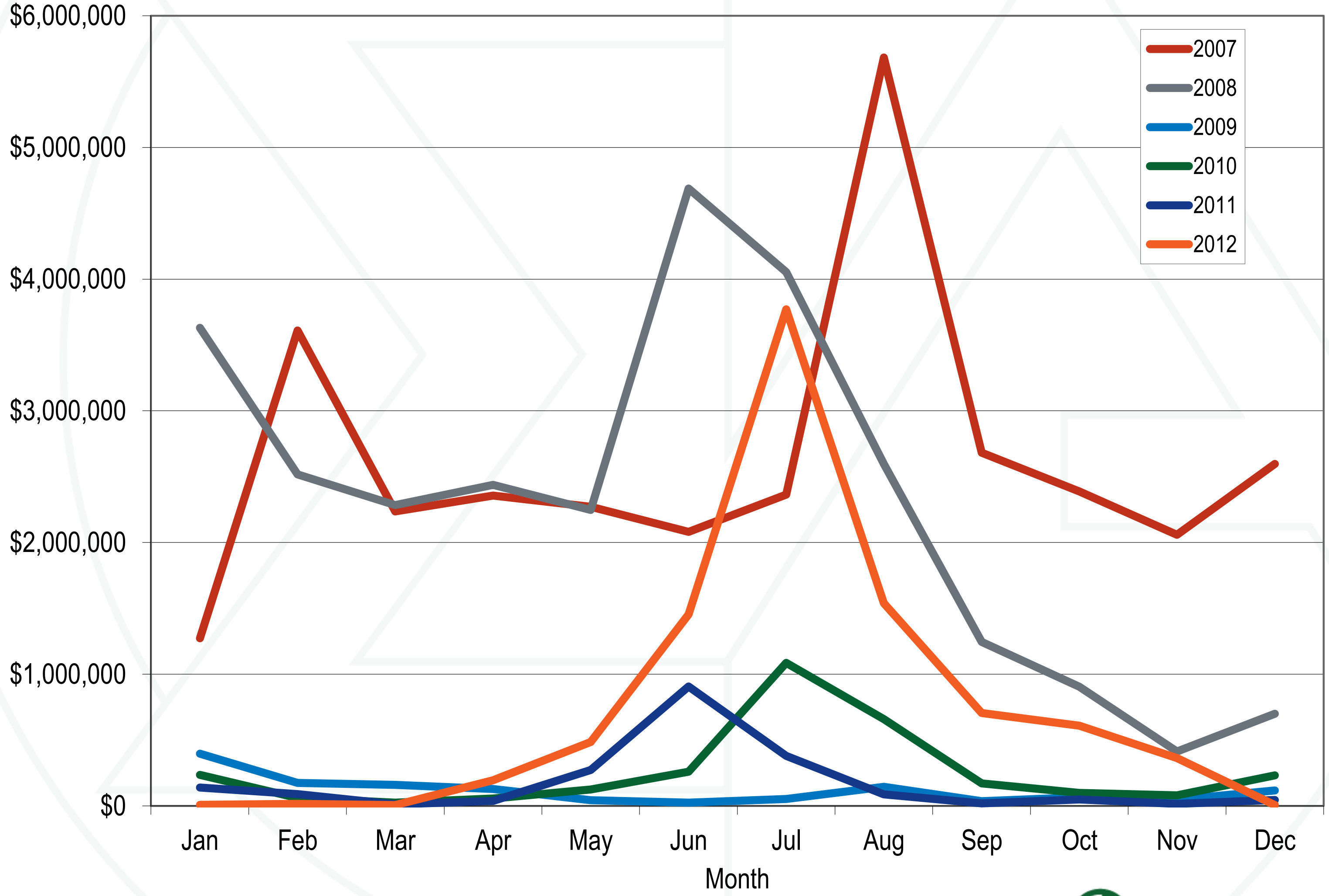


Figure 5-3 Distribution of participant event days across ranges of performance levels across the event in the 2012/2013 Delivery Year compliance period

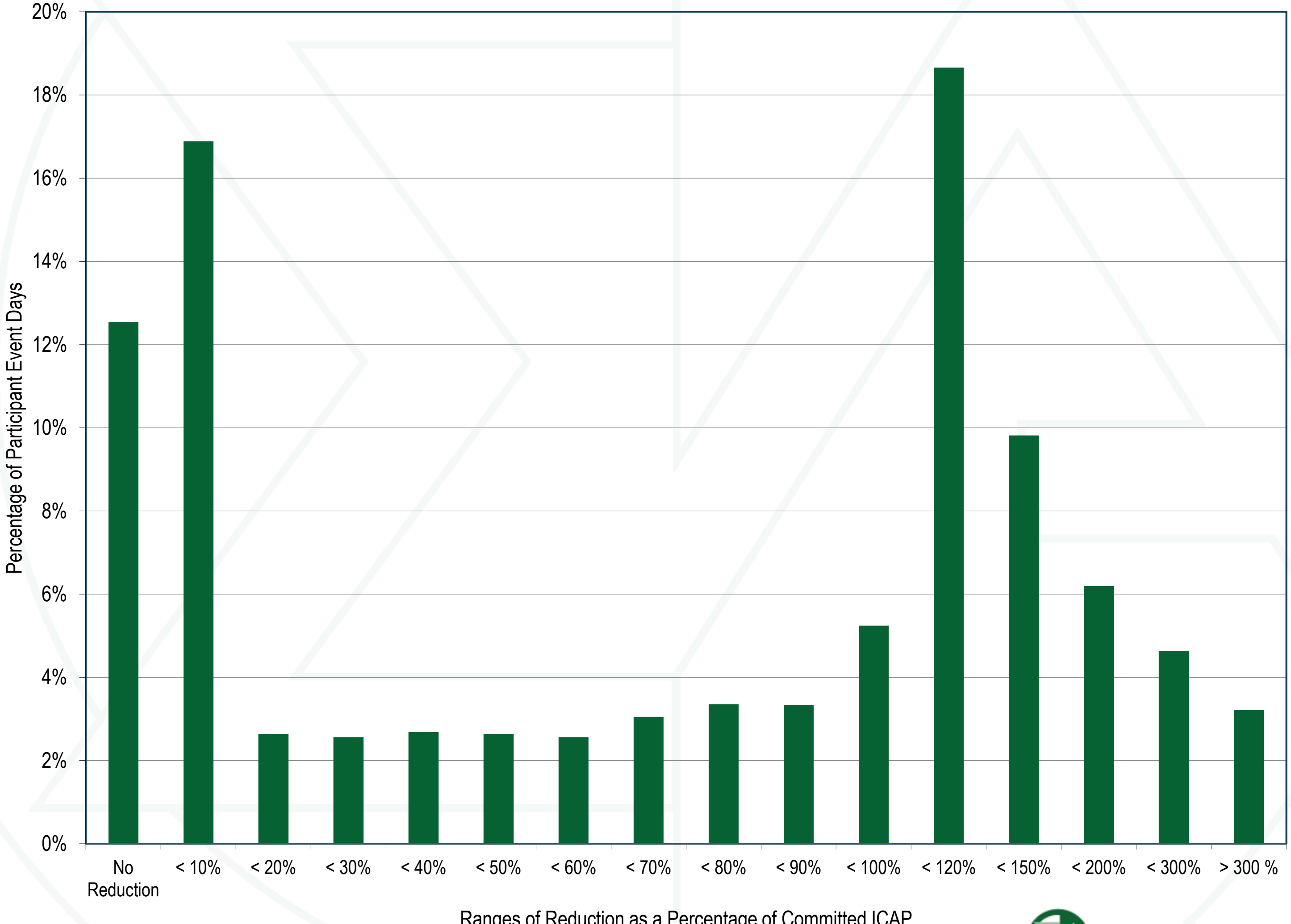


Table 5-21 Load Management Event Performance Comparison: Reported Reduction vs. Actual Reduction: 2012

Zone	Committed MW	Load Reduction Reported (MWh)	Actual Load Reduction (MWh)	Difference	Percent Compliance Reported	Percent Compliance Actual
AECO	32.3	36.1	36.1	0.0	111.9%	111.9%
AEP	1,045.6	1,101.2	1,065.3	36.0	105.3%	101.9%
BGE	794.2	817.6	801.2	16.5	103.0%	100.9%
Dominion	624.4	635.4	603.9	31.4	101.8%	96.7%
DPL	173.5	144.0	144.0	0.0	83.0%	83.0%
JCPL	165.4	192.9	115.1	77.8	116.6%	69.6%
Met-Ed	11.0	15.5	15.5	0.0	141.1%	141.1%
PECO	401.4	408.8	391.3	17.5	101.9%	97.5%
PENELEC	236.4	238.0	226.5	11.5	100.7%	95.8%
Pepco	308.8	330.9	316.8	14.0	107.1%	102.6%
PPL	1.8	1.0	1.0	0.0	56.2%	56.2%
PSEG	10.1	1.1	(3.3)	4.4	10.6%	(32.7%)
Total	3,804.8	3,922.5	3,713.4	209.1	103.1%	97.6%

Table 5-19 Distribution of GLD participant event hours and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2012/2013 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event hours	Proportion of total GLD participant event hours	Cumulative Proportion	Observed reductions (MWh)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	170	9%	9%	0.0	0%	0%
25% - 50%	977	54%	64%	64.6	9%	9%
50% - 75%	269	15%	79%	209.1	30%	40%
75% - 100%	174	10%	88%	44.2	6%	46%
100%	210	12%	100%	367.6	54%	100%
Total	1,800	100%		685.5	100%	

Figure 8-3 PJM's footprint and its external interfaces

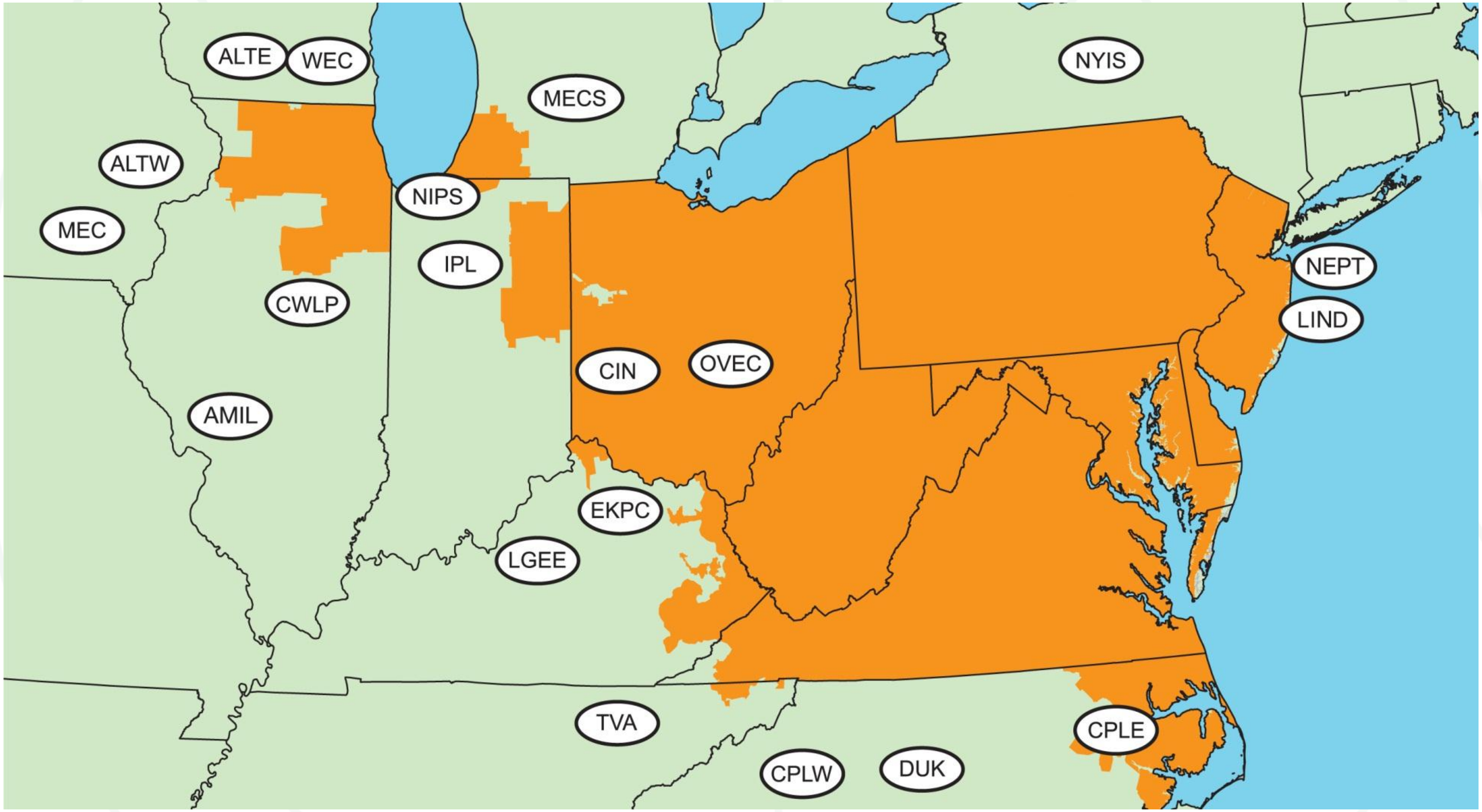
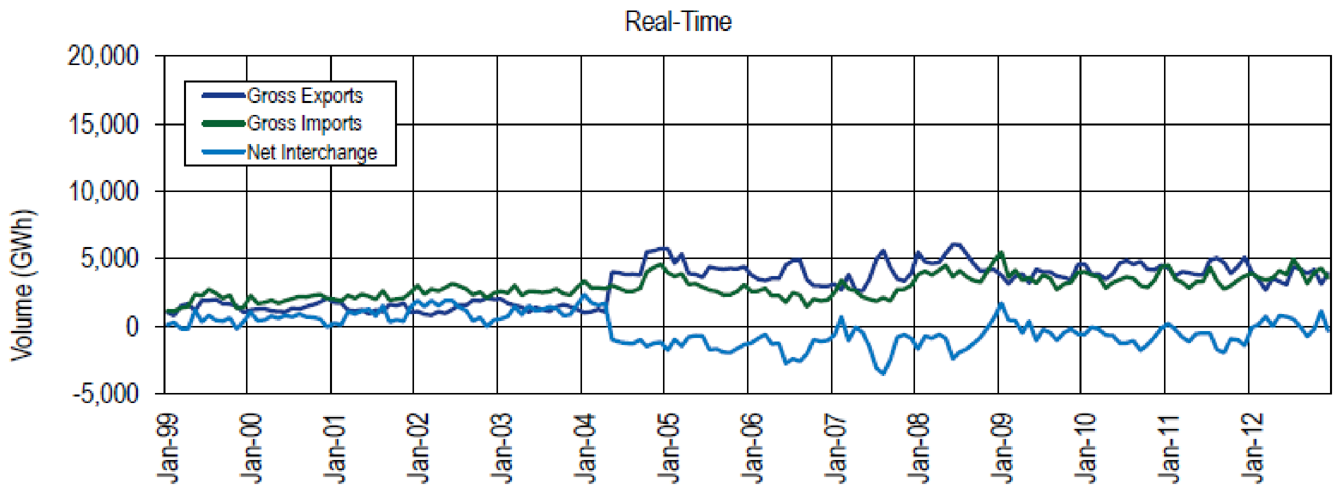


Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 2012



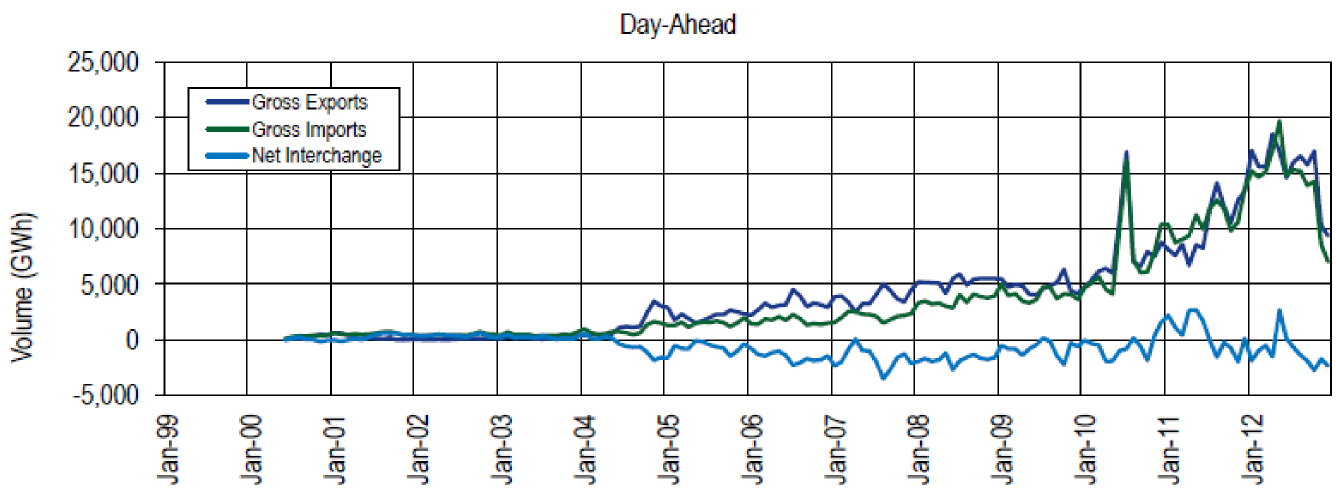
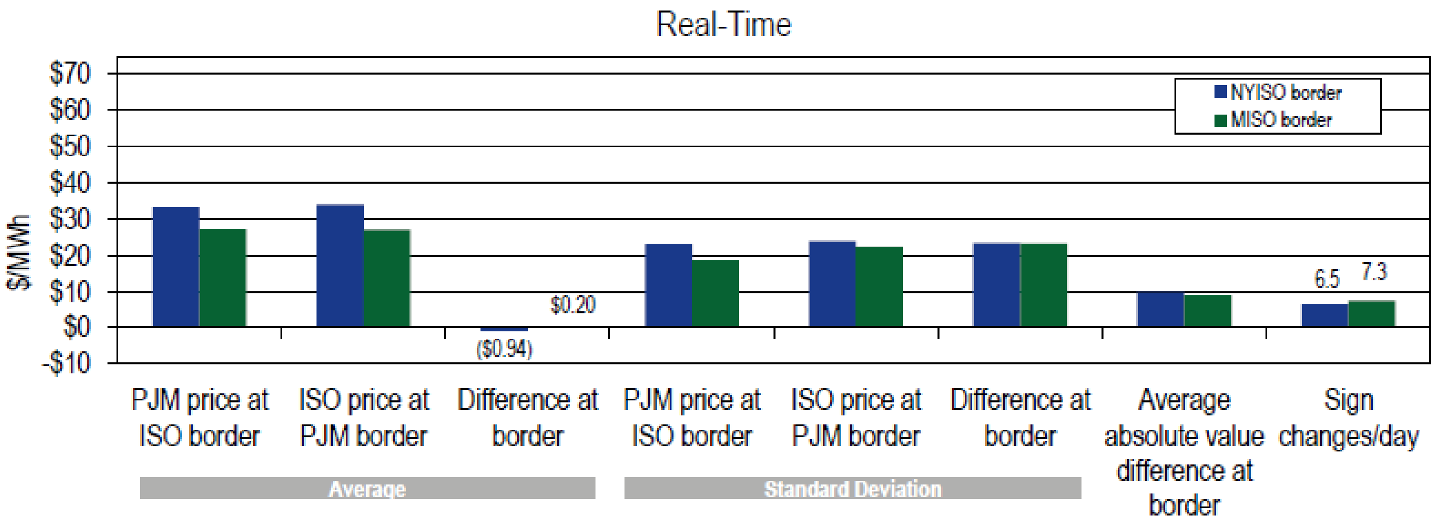


Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: 2012



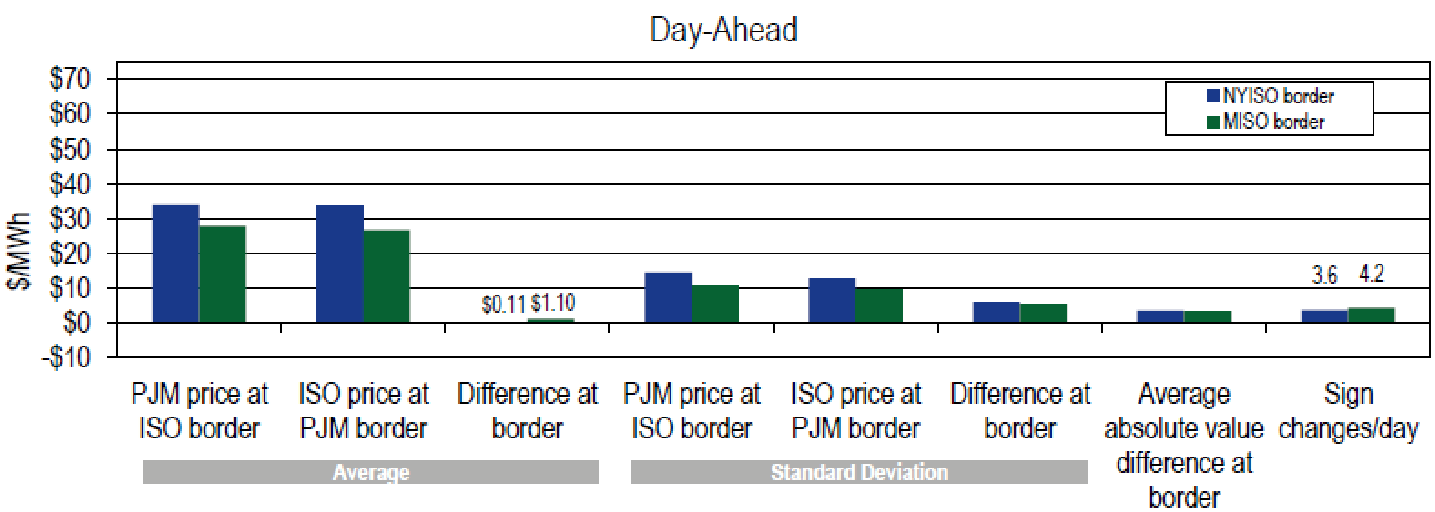


Table 9-4 History of ancillary services costs per MW of Load: 2001 through 2012

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2001	$0.50	$0.44	$0.22	$0.00	$1.07	$2.23
2002	$0.45	$0.53	$0.21	$0.07	$0.63	$1.90
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

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2012

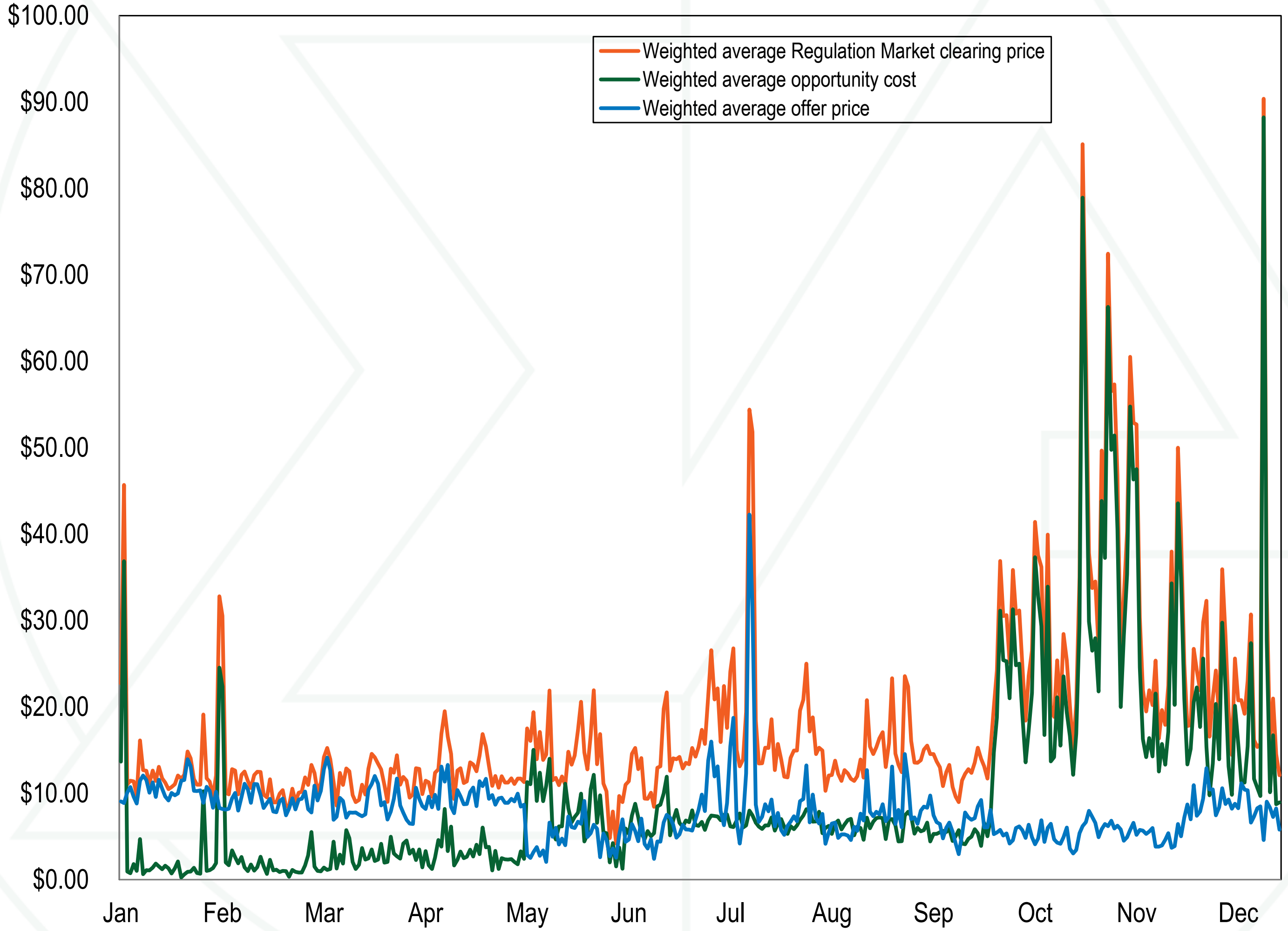


Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through December 2012

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$13.41	$10.58	$2.70
Feb	$11.89	$8.84	$2.68
Mar	$12.61	$8.82	$3.48
Apr	$13.01	$8.63	$4.07
May	$17.44	$6.52	$9.89
Jun	$14.91	$6.21	$6.94
Jul	$20.73	$6.60	$10.70
Aug	$15.86	$6.50	$7.37
Sep	$14.42	$5.46	$7.16
Oct	$39.80	$5.14	$23.94
Nov	$42.71	$5.58	$32.33
Dec	$27.39	$8.50	$20.19
Average	$20.35	$7.28	$10.95

Table 9-14 Comparison of average price and cost for PJM Regulation, 2006 through 2012

Period	Weighted Regulation Market Price ($/MW)	Weighted Regulation Market Cost ($/MW)	Regulation Price as Percent Cost
2006	$32.69	$44.98	73%
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%

Table 9-20 Comparison of yearly weighted average price and cost for PJM Synchronized Reserve, 2005 through 2012

Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%
2012	$6.73	$8.02	$12.71	63%

Figure 12-15 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 through December 2012

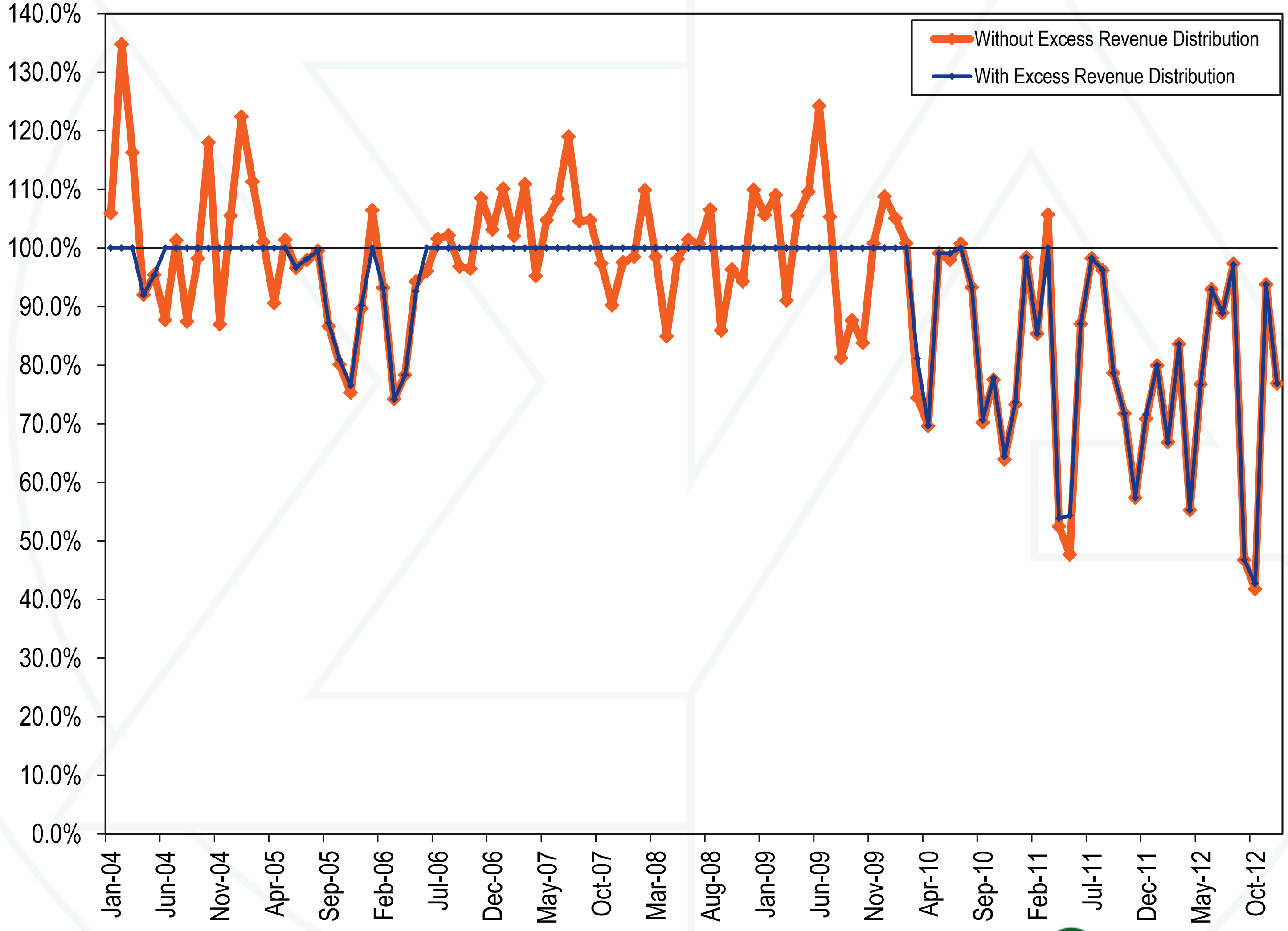


Table 12-29 Monthly positive and negative target allocations and payout ratios with and without hourly netting in 2012

	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-12	$69,520,143	($7,730,433)	$126,702,422	($64,766,863)	$49,465,924	80.1%	90.2%
Feb-12	$66,139,499	($8,722,011)	$124,792,575	($67,369,848)	$38,390,571	66.9%	84.7%
Mar-12	$71,521,584	($13,706,751)	$147,644,281	($89,829,450)	$48,331,587	83.6%	93.6%
Apr-12	$88,301,660	($14,712,532)	$190,422,018	($116,820,311)	$40,645,388	55.2%	82.7%
May-12	$79,061,876	($9,760,027)	$177,551,934	($108,239,496)	$53,188,585	76.7%	90.9%
Jun-12	$69,557,299	($6,623,560)	$121,217,938	($58,280,956)	$58,463,402	92.9%	96.3%
Jul-12	$89,179,225	($9,034,200)	$173,602,611	($93,421,963)	$71,254,665	88.9%	94.9%
Aug-12	$60,694,118	($5,115,960)	$111,642,193	($55,976,928)	$54,064,320	97.3%	98.6%
Sep-12	$99,154,010	($16,477,176)	$179,647,915	($96,844,326)	$38,699,241	46.8%	75.4%
Oct-12	$68,051,707	($9,827,426)	$137,698,279	($79,454,756)	$24,321,860	41.8%	75.4%
Nov-12	$66,233,739	($6,557,217)	$124,142,020	($64,424,379)	$52,049,442	87.2%	93.8%
Dec-12	$54,866,078	($4,610,245)	$110,328,974	($59,848,711)	$36,295,666	72.2%	87.1%
Total	$882,280,937	($112,877,538)	$1,725,393,160	($955,277,987)	$565,170,652	73.5%	88.1%

Table 12-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2012 to 2013

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	14.9%	1.5%	11.2%
		No	29.3%	20.7%	26.9%
		Total	44.2%	22.2%	38.2%
	Financial	No	55.8%	77.8%	61.8%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		12.5%	4.8%	9.5%
	Financial		87.5%	95.2%	90.5%
	Total		100.0%	100.0%	100.0%

Table 12-40 ARR and FTR congestion offset (in millions) by control zone: Planning period 2012 to 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$5.9	$0.4	$5.8	$0.6	$5.9	($5.3)	10.3%
AEP	$107.1	$56.6	$121.7	$42.0	$66.7	($24.7)	63.0%
APS	$76.2	$13.6	$40.3	$49.5	$36.3	$13.2	>100%
ATSI	$4.3	$10.0	($0.7)	$15.0	$2.4	$12.6	>100%
BGE	$31.5	$14.6	$42.3	$3.9	$16.0	($12.1)	24.4%
ComEd	$121.4	$68.1	$82.7	$106.8	$107.0	($0.2)	99.8%
DAY	$3.8	$3.6	$5.3	$2.1	$4.9	($2.8)	42.5%
DEOK	$1.4	$5.7	$3.9	$3.1	$2.6	$0.5	>100%
DLCO	$7.2	$0.4	$7.7	($0.1)	$1.4	($1.5)	0.0%
Dominion	$79.3	$49.3	$110.1	$18.5	$43.1	($24.7)	42.8%
DPL	$12.3	$24.0	$19.3	$17.0	$16.6	$0.4	>100%
External	$7.5	($1.6)	$1.7	$4.2	($30.4)	$34.6	>100%
JCPL	$9.3	$3.3	$20.1	($7.5)	$9.2	($16.7)	0.0%
Met-Ed	$9.0	$6.2	$15.9	($0.6)	$0.2	($0.8)	0.0%
PECO	$20.1	$17.8	$18.1	$19.8	($1.2)	$21.0	>100%
PENELEC	$11.8	$18.2	$30.8	($0.8)	$19.1	($19.9)	0.0%
Pepco	$27.1	$18.9	$81.0	($35.0)	$16.5	($51.5)	0.0%
PPL	$20.2	$4.4	$10.3	$14.3	$8.0	$6.3	>100%
PSEG	$24.0	$19.1	$33.0	$10.0	($3.2)	$13.2	>100%
RECO	$0.0	($0.1)	($1.8)	$1.7	$0.9	$0.8	>100%
Total	$579.6	$332.6	$647.6	$264.6	$322.1	($57.5)	82.1%

Table 12-12 Comparison of self-scheduled FTRs: Planning periods from 2008 to 2009 through 2012 to 2013

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%

Figure 2-22 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2012

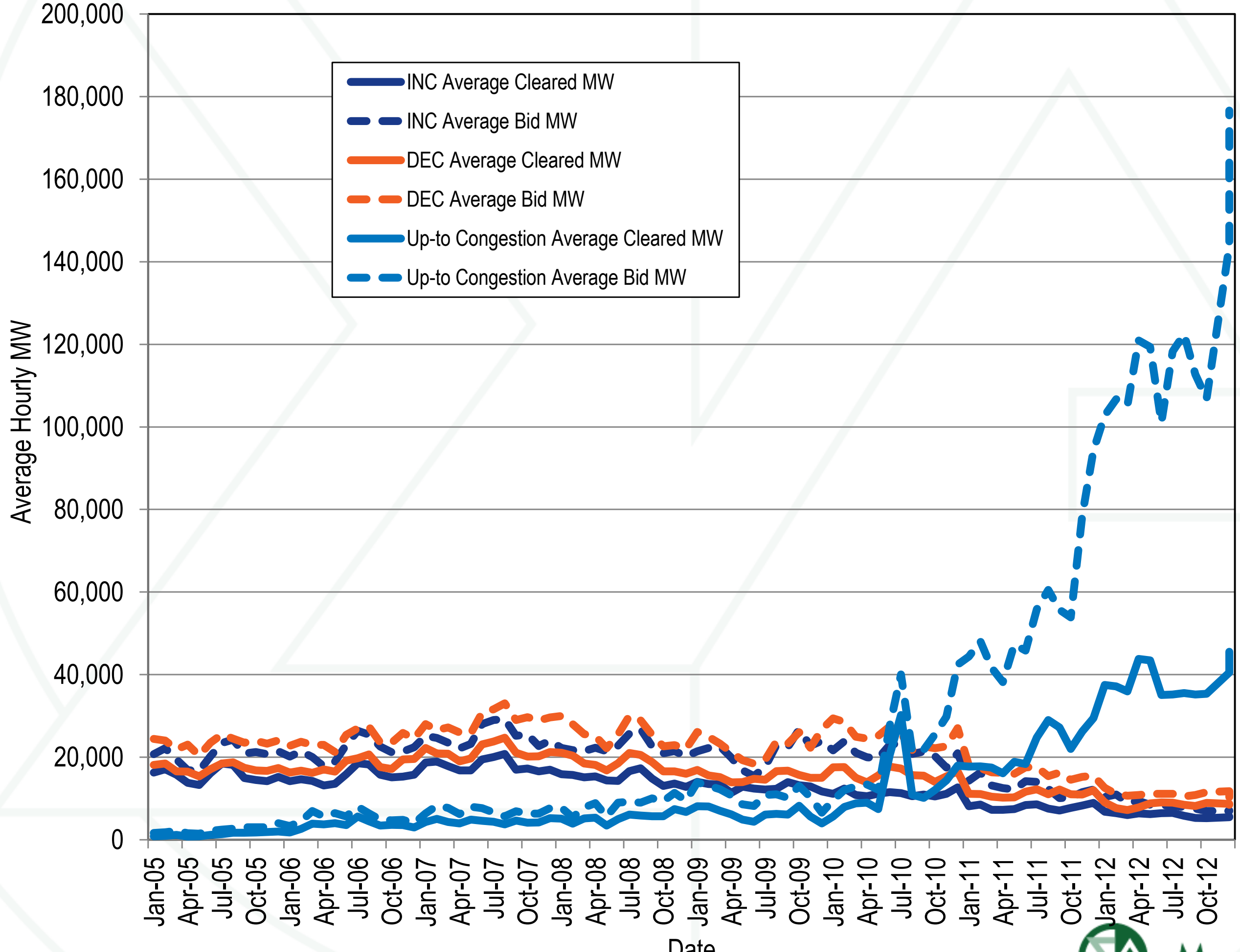


Figure 2-23 PJM cleared up-to congestion transactions by type (MW): 2011 and 2012

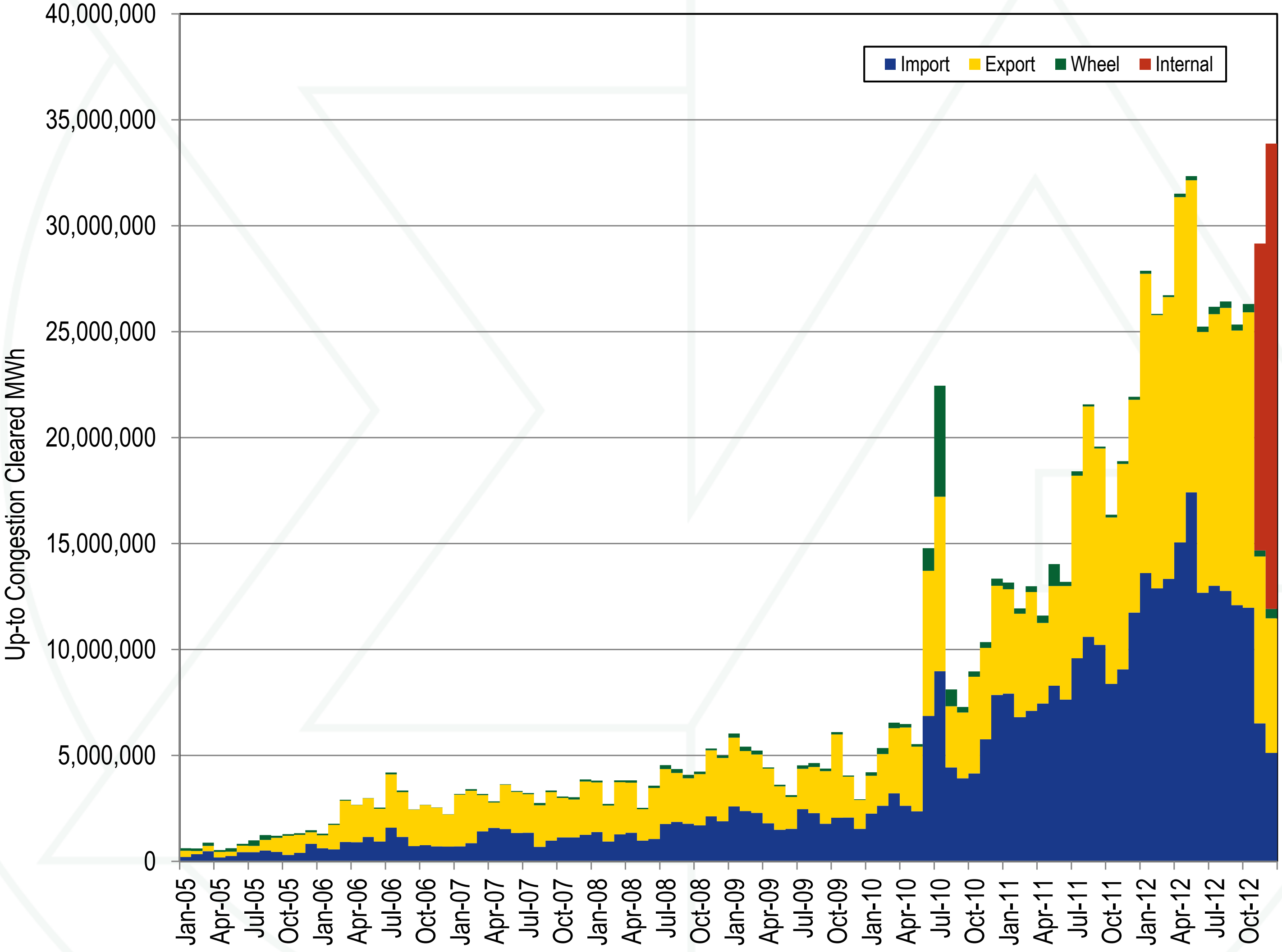


Table 2-50 PJM up-to congestion transactions by type of parent organization (MW): 2011 and 2012

	2011		2012	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	187,509,868	96.8%	318,217,668	94.7%
Physical	6,113,860	3.2%	17,660,315	5.3%
Total	193,623,729	100.0%	335,877,984	100.0%

Table 3-42 Up-to congestion transactions impact on operating reserve rates: 2012

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.2001	0.1775	(0.0226)	(11.3%)
RTO Deviations	0.8147	0.3317	(0.4830)	(59.3%)
East Deviations	0.3332	0.1910	(0.1422)	(42.7%)
West Deviations	0.1265	0.0381	(0.0884)	(69.9%)
Lost Opportunity Cost	1.3223	0.5384	(0.7839)	(59.3%)
Canceled Resources	0.0235	0.0096	(0.0139)	(59.3%)

Table 2-57 PJM cleared up-to congestion transactions by type (MW): 2011 and 2012

	2011 Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	19,649,082	19,782,624	1,762,903	NA	20,850,203
PJM total (MW)	104,786,982	85,627,554	3,209,193	NA	193,623,729
Top ten total as percent of PJM total	18.8%	23.1%	54.9%	NA	10.8%
PJM total as percent of all up-to congestion transactions	54.1%	44.2%	1.7%	NA	100.0%
	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%

Market Monitoring Unit

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

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