2010 State of the Market Report for PJM

Monitoring Analytics, LLC
Independent Market Monitor for PJM

March 10, 2011

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Market Monitor

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

Role of Market Monitoring

- **Market monitoring is required by FPA/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 – like other markets/exchanges**
- **Detailed monitoring required to ensure competitive outcomes:**
  - Of participants
  - Of RTO
  - Of rules

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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**

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Market Monitoring Plan

- **Monitor compliance with rules, standards, procedures and practices of PJM.**
- **Monitor actual or potential design flaws in rules, standards, procedures and practices of PJM.**
- **Monitor structural problems in the PJM market that may inhibit a robust and competitive market.**
- **Monitor the potential of Market Participants to exercise undue market power.**

Figure 1-1 PJM's footprint and its 17 control zones (See 2009 SOM, Figure A-1)

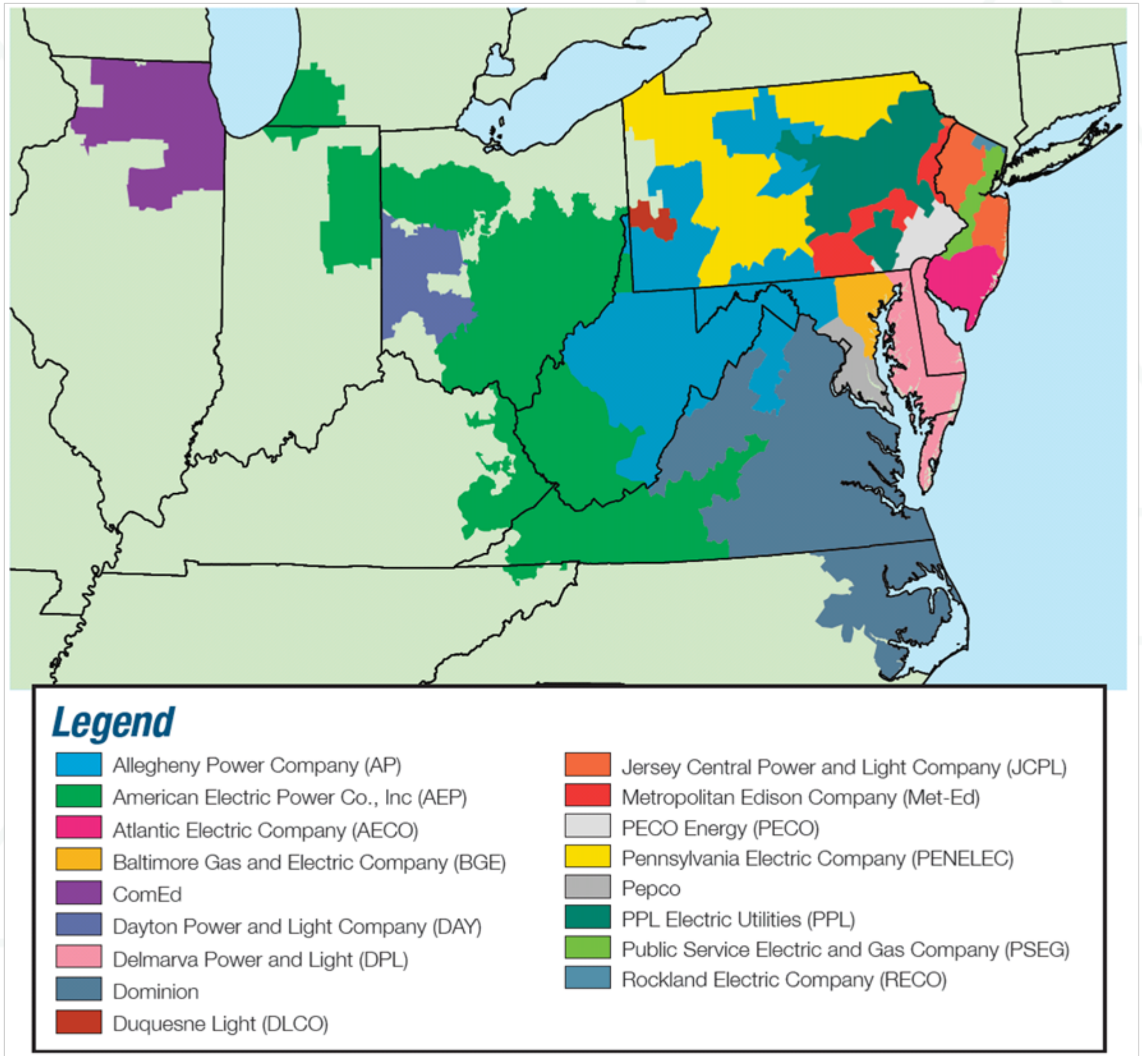

Table 1-1 The Energy Market results were competitive

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

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

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	
Performance	**Competitive**	**Effective**

State of the Market Recommendations

- Modifications to the capacity market rules to ensure that:
  - prices reflect full supply and demand
  - local prices reflect local market conditions
- Must offer energy requirement for all capacity resources
- Eliminate 2.5 percent demand offset
- Consider implications of potential loss of at risk coal units

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State of the Market Recommendations

- Modification of regulation market rules
  - Modify opportunity cost calculation
  - Modify regulation offset against operating reserves
- Elimination of minimum dispatch price under Demand Side Emergency Response Program Full option as inefficient and unnecessary
- Eliminate use of internal buses for import and export transactions, including “up to congestion” transactions

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State of the Market Recommendations

- Modification of rules governing demand-side programs to ensure accurate measurement, verification and payment.
- Provision of data for external control areas to PJM to enable improved analysis of loop flows in order to enhance the efficiency of PJM markets.

Table 1-7 Total price per MWh by category and total revenues by category: Calendar years 2009 and 2010

Category	Totals ($ Millions) 2009	Totals ($ Millions) 2010	Percent Change Totals	2009 $/MWh	2010 $/MWh	Percent Change $/MWh	2009 Proportion of $/MWh	2010 Proportion of $/MWh	Percent Change in Proportions
Energy	$26,008.22	$33,717.30	29.6%	$39.05	$48.35	23.8%	69.9%	72.5%	3.6%
Capacity	$7,338.36	$8,409.34	14.6%	$11.02	$12.06	9.4%	19.7%	18.1%	(8.4%)
Transmission Service Charges	$2,663.31	$2,786.58	4.6%	$4.00	$4.00	(0.1%)	7.2%	6.0%	(16.4%)
Operating Reserves (Uplift)	$321.83	$547.68	70.2%	$0.48	$0.79	62.5%	0.9%	1.2%	36.0%
Reactive	$242.32	$310.08	28.0%	$0.36	$0.44	22.2%	0.7%	0.7%	2.3%
PJM Administrative Fees	$203.49	$248.02	21.9%	$0.31	$0.36	16.4%	0.5%	0.5%	(2.6%)
Regulation	$228.18	$241.39	5.8%	$0.34	$0.35	1.0%	0.6%	0.5%	(15.4%)
Transmission Enhancement Cost Recovery	$63.21	$139.36	120.5%	$0.09	$0.20	110.6%	0.2%	0.3%	76.2%
Transmssion Owner (Schedule 1A)	$56.47	$61.38	8.7%	$0.08	$0.09	3.8%	0.2%	0.1%	(13.1%)
Synchronized Reserves	$34.27	$43.85	27.9%	$0.05	$0.06	22.2%	0.1%	0.1%	2.3%
NERC/RFC	$8.86	$13.81	56.0%	$0.01	$0.02	49.0%	0.0%	0.0%	24.7%
Black Start	$14.27	$11.45	(19.7%)	$0.02	$0.02	(23.3%)	0.0%	0.0%	(35.8%)
RTO Startup and Expansion	$9.12	$8.99	(1.4%)	$0.01	$0.01	(5.9%)	0.0%	0.0%	(21.2%)
Day Ahead Scheduling Reserve (DASR)	$2.32	$7.37	217.7%	$0.00	$0.01	203.5%	0.0%	0.0%	154.0%
Load Response	$1.35	$3.11	129.9%	$0.00	$0.00	119.6%	0.0%	0.0%	83.8%
Transmission Facility Charges	$1.39	$1.39	(0.4%)	$0.00	$0.00	(4.9%)	0.0%	0.0%	(20.4%)
Total	$37,196.97	$46,530.41	25.1%	$55.85	$66.72	19.5%	100.0%	100.0%	0.0%

Figure 2-1 Average PJM aggregate supply curves: Summers 2009 and 2010

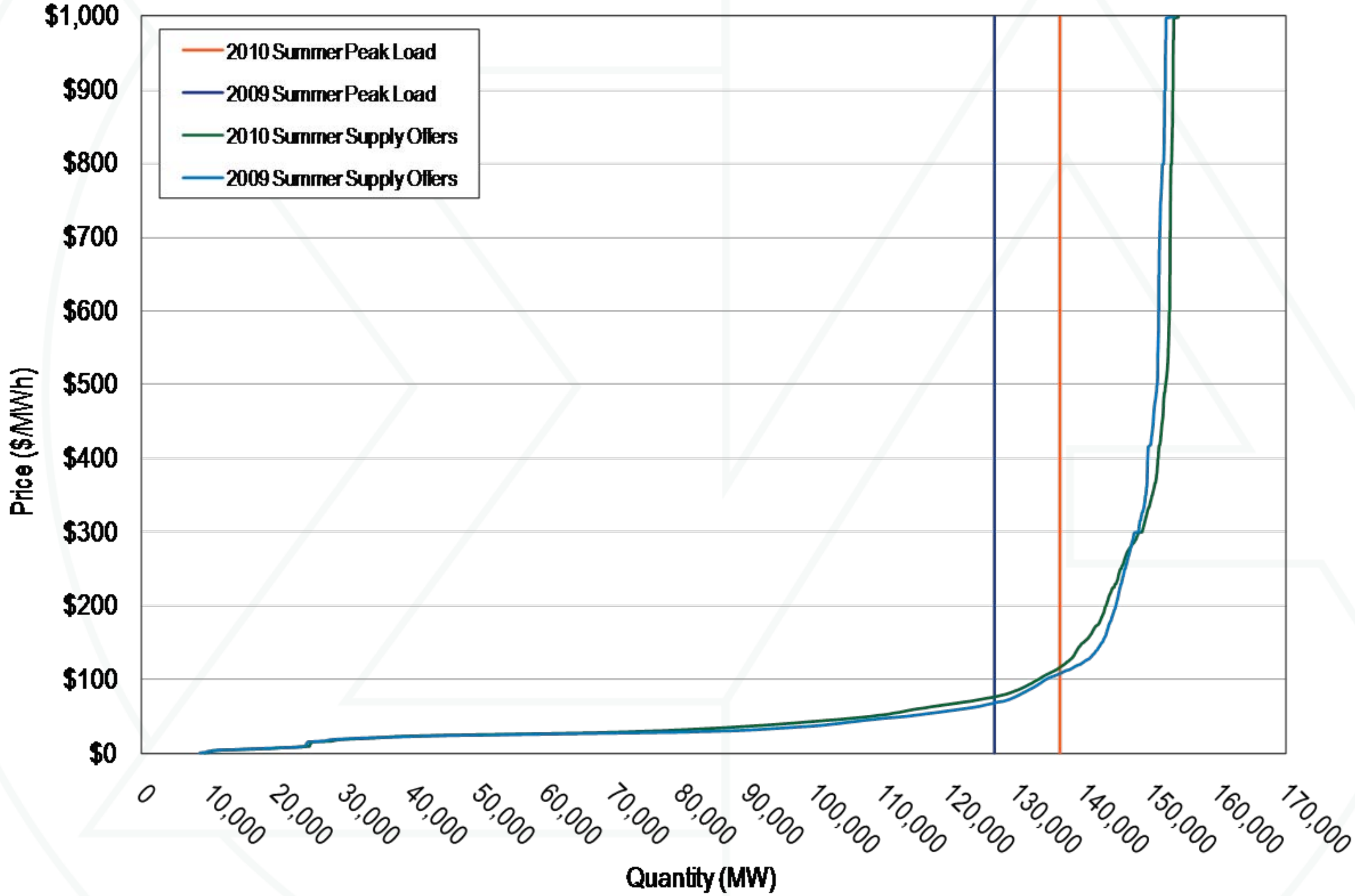

Table 3-42 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2010

	1-Jan-10		31-May-10		1-Jun-10		31-Dec-10	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	68,382.1	40.7%	68,155.5	40.7%	67,991.1	40.8%	68,007.0	40.8%
Gas	**49,238.8**	**29.3%**	**48,991.4**	**29.3%**	**48,424.5**	**29.0%**	**48,513.8**	**29.1%**
Hydroelectric	7,921.9	4.7%	7,923.5	4.7%	7,923.5	4.8%	7,954.5	4.8%
Nuclear	**30,611.9**	**18.2%**	**30,599.3**	**18.3%**	**30,619.0**	**18.4%**	**30,552.2**	**18.3%**
Oil	10,700.1	6.4%	10,649.4	6.4%	10,645.5	6.4%	10,193.6	6.1%
Solid waste	**672.1**	**0.4%**	**672.1**	**0.4%**	**672.1**	**0.4%**	**680.1**	**0.4%**
Wind	326.9	0.2%	409.5	0.2%	481.1	0.3%	610.9	0.4%
Total	**167,853.8**	**100.0%**	**167,400.7**	**100.0%**	**166,756.8**	**100.0%**	**166,512.1**	**100.0%**

Table 3-43 PJM generation (By fuel source (GWh)): Calendar year 2010

	2009 GWh	Percent	2010 GWh	Percent	Change in Output
Coal	349,818.2	50.5%	362,075.4	49.3%	3.5%
Nuclear	**249,392.3**	**36.0%**	**254,534.1**	**34.6%**	**2.1%**
Gas	67,218.9	9.7%	86,265.5	11.7%	28.3%
Natural Gas	65,848.2	9.5%	84,570.1	11.5%	28.4%
Landfill Gas	1,368.5	0.2%	1,695.0	0.2%	23.9%
Biomass Gas	2.2	0.0%	0.5	0.0%	(78.9%)
Hydroelectric	**14,123.0**	**2.0%**	**14,384.4**	**2.0%**	**1.9%**
Wind	5,489.7	0.8%	8,812.8	1.2%	60.5%
Waste	**5,664.7**	**0.8%**	**5,356.6**	**0.7%**	**(5.4%)**
Solid Waste	**4,147.0**	**0.6%**	**4,157.5**	**0.6%**	**0.3%**
Miscellaneous	**1,517.7**	**0.2%**	**1,199.1**	**0.2%**	**(21.0%)**
Oil	1,568.1	0.2%	3,243.2	0.4%	106.8%
Heavy Oil	1,383.7	0.2%	2,748.3	0.4%	98.6%
Light Oil	162.9	0.0%	446.9	0.1%	174.3%
Diesel	14.4	0.0%	32.3	0.0%	123.9%
Kerosene	7.1	0.0%	15.7	0.0%	120.8%
Jet Oil	0.0	0.0%	0.1	0.0%	51.9%
Solar	**3.5**	**0.0%**	**5.7**	**0.0%**	**64.7%**
Battery	0.3	0.0%	0.3	0.0%	18.9%
Total	**693,278.7**	**100.0%**	**734,678.2**	**100.0%**	**6.0%**

Table 2-14 Type of fuel used (By real-time marginal units): Calendar year 2010

Fuel Type	2010
Coal	68%
Gas	26%
Oil	4%
Wind	2%
Municipal Waste	1%

Figure 2-2 Actual PJM footprint peak loads: 1999 to 2010

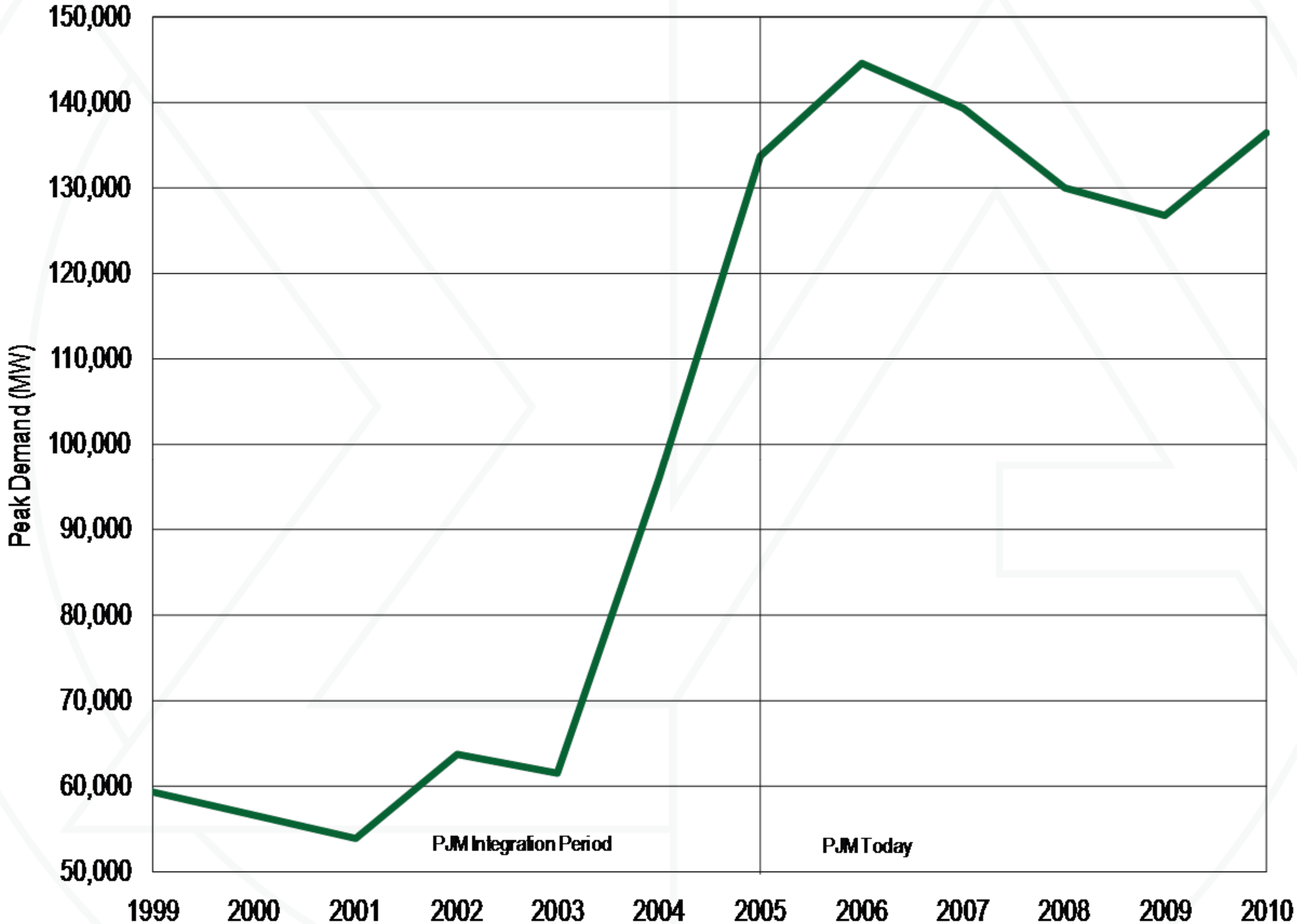

Table 2-28 PJM real-time average hourly load: Calendar years 1998 to 2010

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	**81,681**	**80,914**	**14,618**	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	**76,035**	**75,471**	**13,260**	(4.4%)	(3.8%)	(3.6%)
2010	79,611	77,430	15,504	4.7%	2.6%	16.9%

Figure 2-6 PJM real-time average hourly load: Calendar years 2009 to 2010

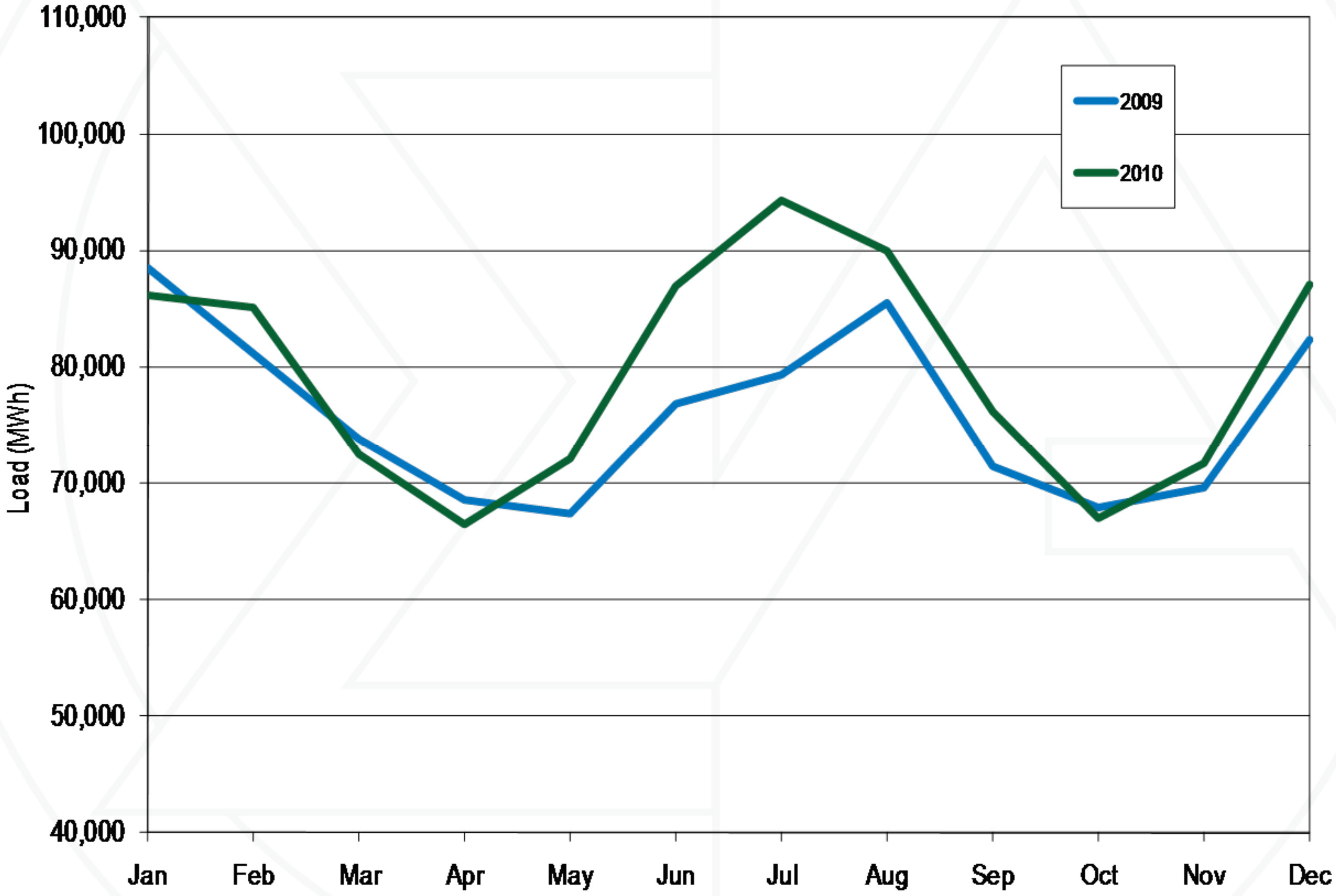

Table 2-38 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2010

	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%

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 to 2010

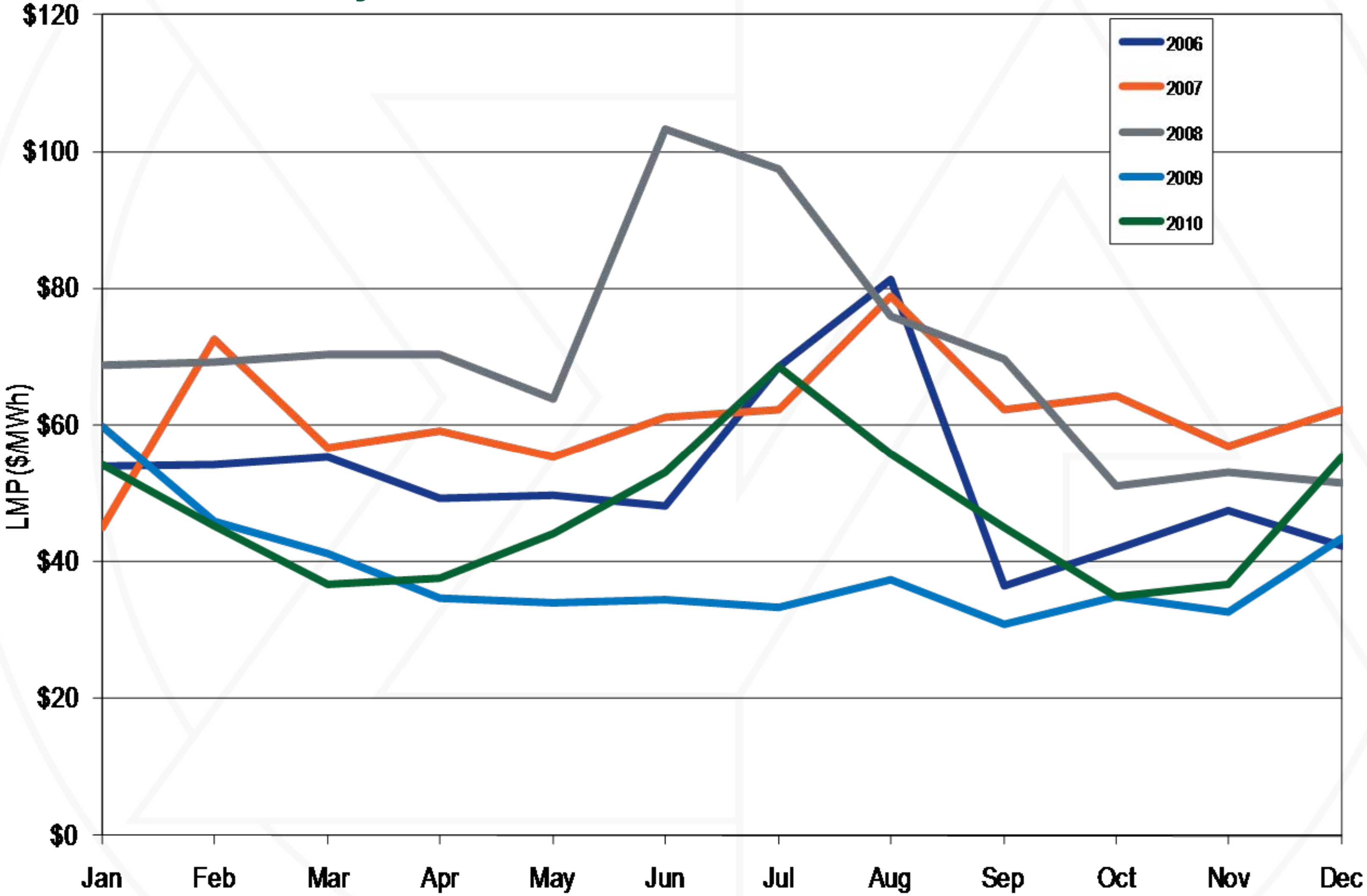

Figure 2-15 Spot average fuel price comparison: Calendar years 2009 to 2010

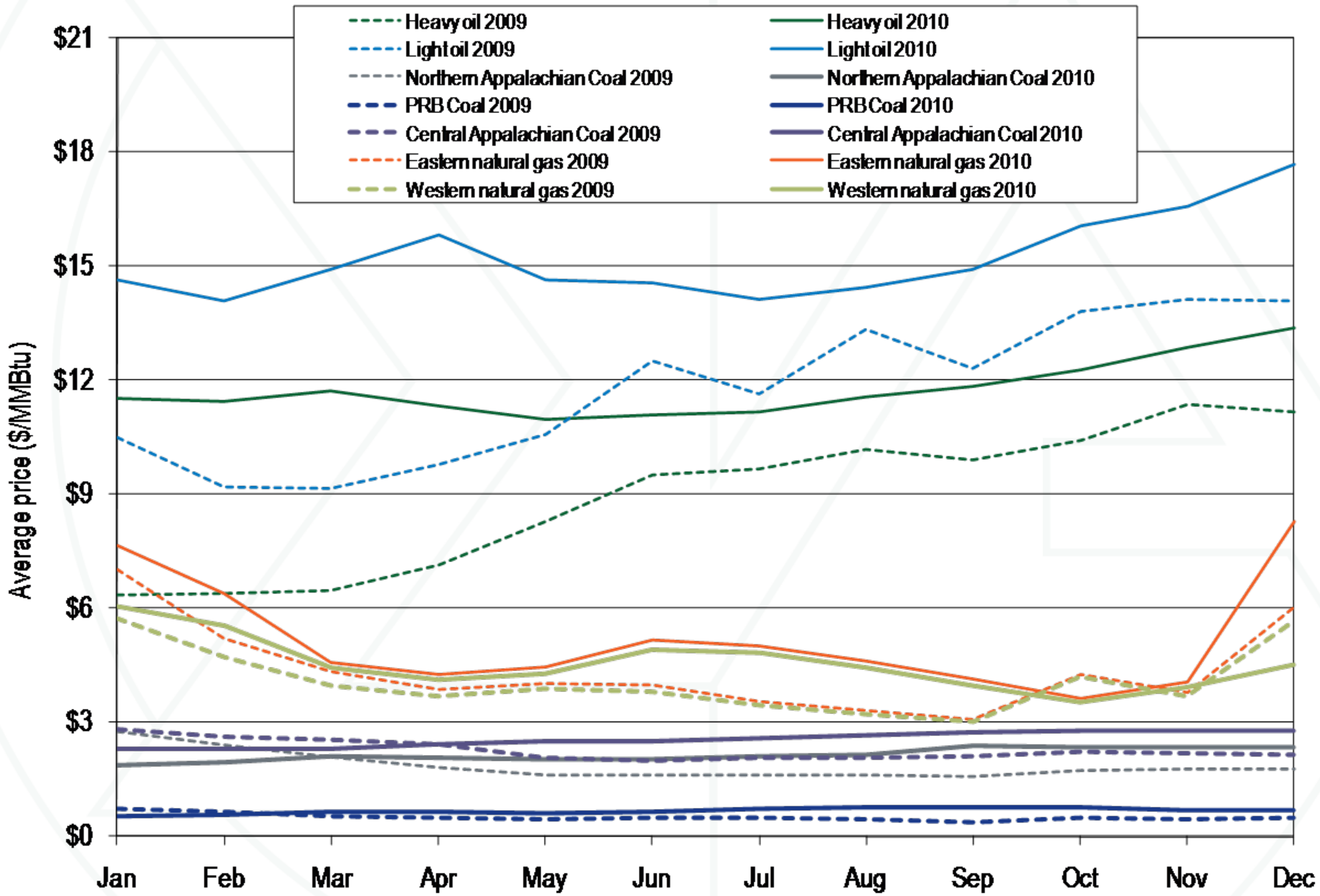

Figure 3-16 Spot average emission price comparison: Calendar years 2009 to 2010

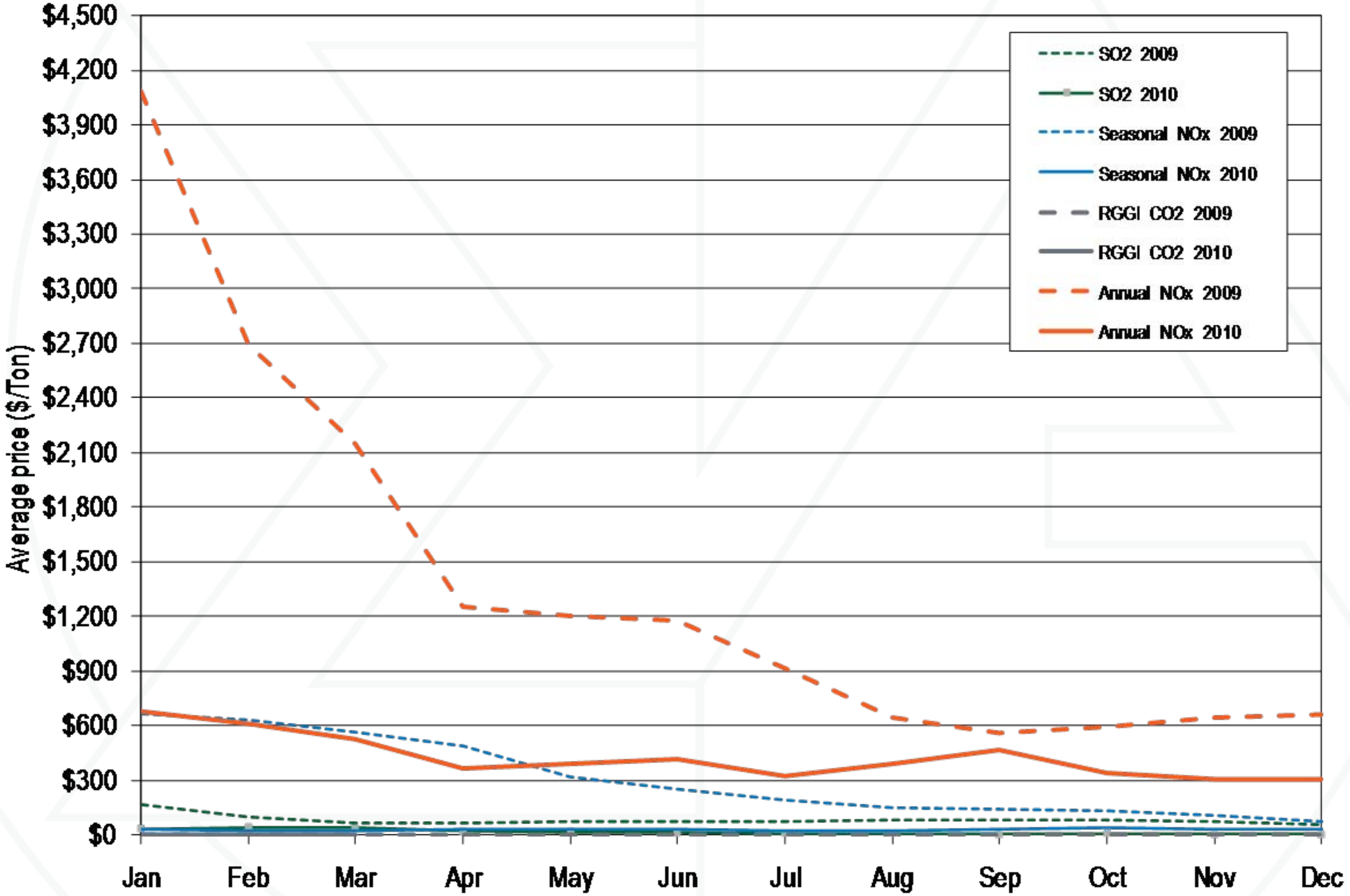

Table 2-41 PJM real-time annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2010 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$48.35	$46.70	(3.4%)
	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.05	$46.70	19.6%
	2009 Load-Weighted LMP	2010 Load-Weighted LMP	Change
Average	$39.05	$48.35	23.8%

Table 2-42 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2010

Element	Contribution to LMP	Percent
Coal	$19.07	39.4%
Gas	$18.12	37.5%
10% Cost Adder	$4.19	8.7%
VOM	$2.64	5.5%
Oil	$1.78	3.7%
NO_X	$0.86	1.8%
NA	$0.57	1.2%
CO_2	$0.40	0.8%
Markup	$0.31	0.6%
SO_2	$0.25	0.5%
FMU Adder	$0.11	0.2%
Dispatch Differential	$0.06	0.1%
Shadow Price Limit Adder	$0.03	0.1%
Municipal Waste	$0.01	0.0%
Offline CT Adder	$0.00	0.0%
M2M Adder	($0.00)	(0.0%)
Wind	($0.02)	(0.0%)
Unit LMP Differential	($0.03)	(0.1%)
Total	$48.35	100.0%

Table 2-63 PJM virtual bids by type of bid parent organization (MW): Calendar year 2010

	Category	Total Virtual Bids MW	Percentage
2010	Financial	169,223,448	41.8%
2010	Physical	235,801,427	58.2%
2010	Total	405,024,876	100.0%

Table 2-64 PJM virtual bids by top ten aggregates (MW): Calendar year 2010

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	59,498,730	67,461,162	126,959,892
N ILLINOIS HUB	HUB	12,227,336	13,489,896	25,717,232
AEP-DAYTON HUB	HUB	5,903,338	7,754,931	13,658,269
PPL	ZONE	524,776	8,491,950	9,016,726
PSEG	ZONE	2,412,903	5,229,766	7,642,670
BGE	ZONE	3,675,033	3,624,029	7,299,062
Pepco	ZONE	5,922,591	1,215,146	7,137,737
JCPL	ZONE	3,939,569	2,210,312	6,149,881
MISO	INTERFACE	1,223,082	3,768,471	4,991,553
ComEd	ZONE	2,251,251	2,422,361	4,673,613
Top ten total		97,578,609	115,668,025	213,246,633
PJM total		184,846,624	220,178,252	405,024,876
Top ten total as percent of PJM total		52.8%	52.5%	52.7%

Table 2-66 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2010

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2000	$31.97	$30.36	($1.61)	(5.0%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%

Figure 2-19 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2010

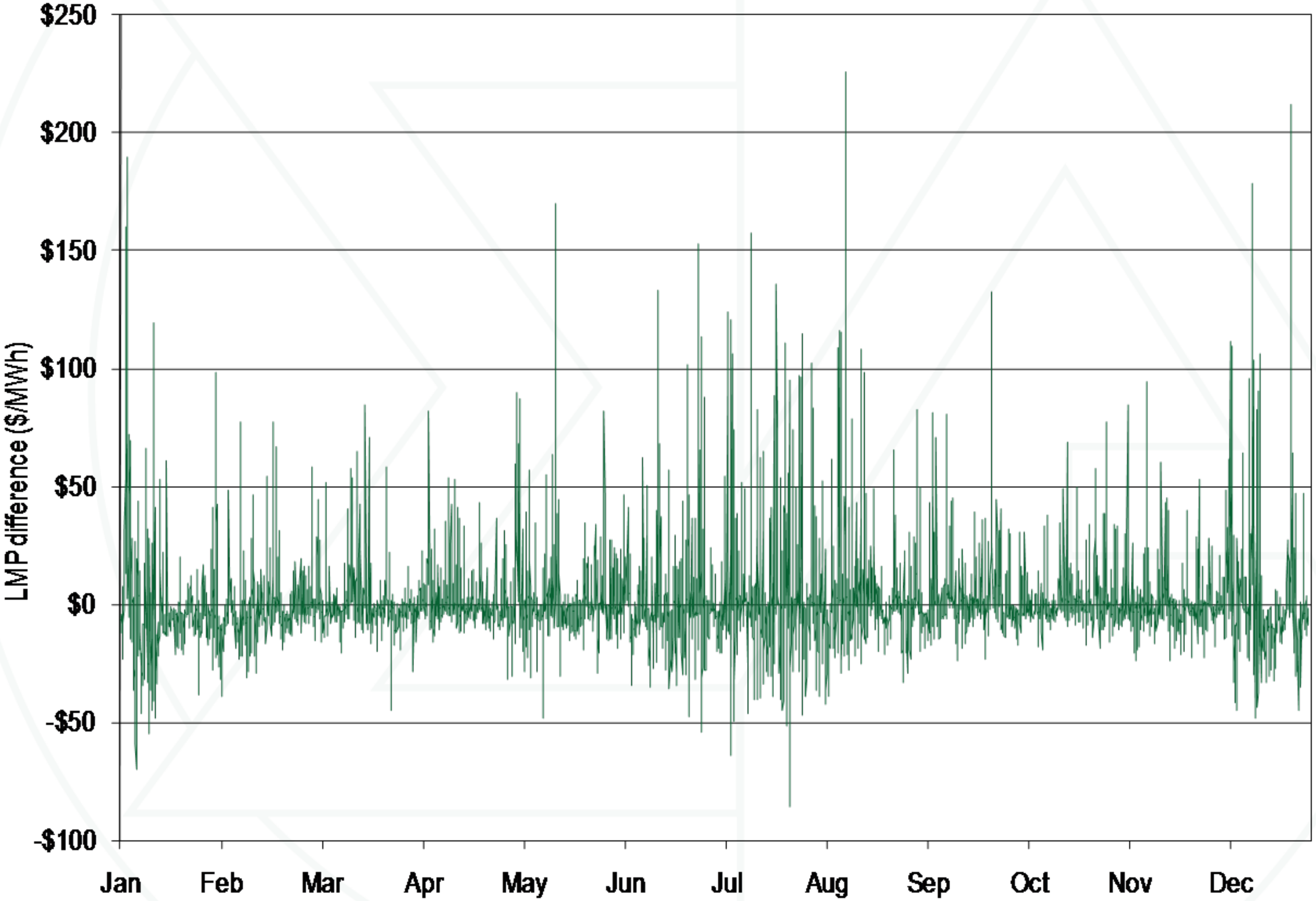

Table 2-70 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2009 to 2010

	2009			2010			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	12.6%	15.4%	72.0%	12.0%	17.4%	70.5%	(0.6%)	2.1%	(1.5%)
Feb	13.4%	14.5%	72.1%	13.5%	18.1%	68.4%	0.0%	3.7%	(3.7%)
Mar	13.8%	16.7%	69.5%	12.8%	18.2%	68.9%	(0.9%)	1.5%	(0.6%)
Apr	13.5%	17.2%	69.3%	12.6%	19.3%	68.1%	(0.9%)	2.0%	(1.2%)
May	14.6%	18.8%	66.7%	11.6%	19.9%	68.5%	(3.0%)	1.1%	1.9%
Jun	12.5%	16.5%	71.0%	10.4%	19.0%	70.5%	(2.1%)	2.5%	(0.5%)
Jul	12.6%	16.9%	70.5%	9.8%	19.5%	70.7%	(2.8%)	2.5%	0.2%
Aug	11.7%	16.0%	72.3%	10.6%	20.5%	68.9%	(1.2%)	4.5%	(3.4%)
Sep	12.5%	18.1%	69.4%	12.0%	22.3%	65.7%	(0.5%)	4.2%	(3.7%)
Oct	13.0%	19.8%	67.2%	13.0%	25.1%	61.9%	(0.0%)	5.3%	(5.3%)
Nov	13.2%	19.0%	67.8%	12.8%	22.7%	64.5%	(0.4%)	3.7%	(3.4%)
Dec	11.7%	16.8%	71.5%	11.5%	21.8%	66.7%	(0.2%)	5.0%	(4.8%)
Annual	12.9%	17.0%	70.1%	11.8%	20.2%	68.0%	(1.1%)	3.2%	(2.1%)

Table 2-7 Annual offer-capping statistics: Calendar years 2006 to 2010

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
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%

Figure 3-5 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010

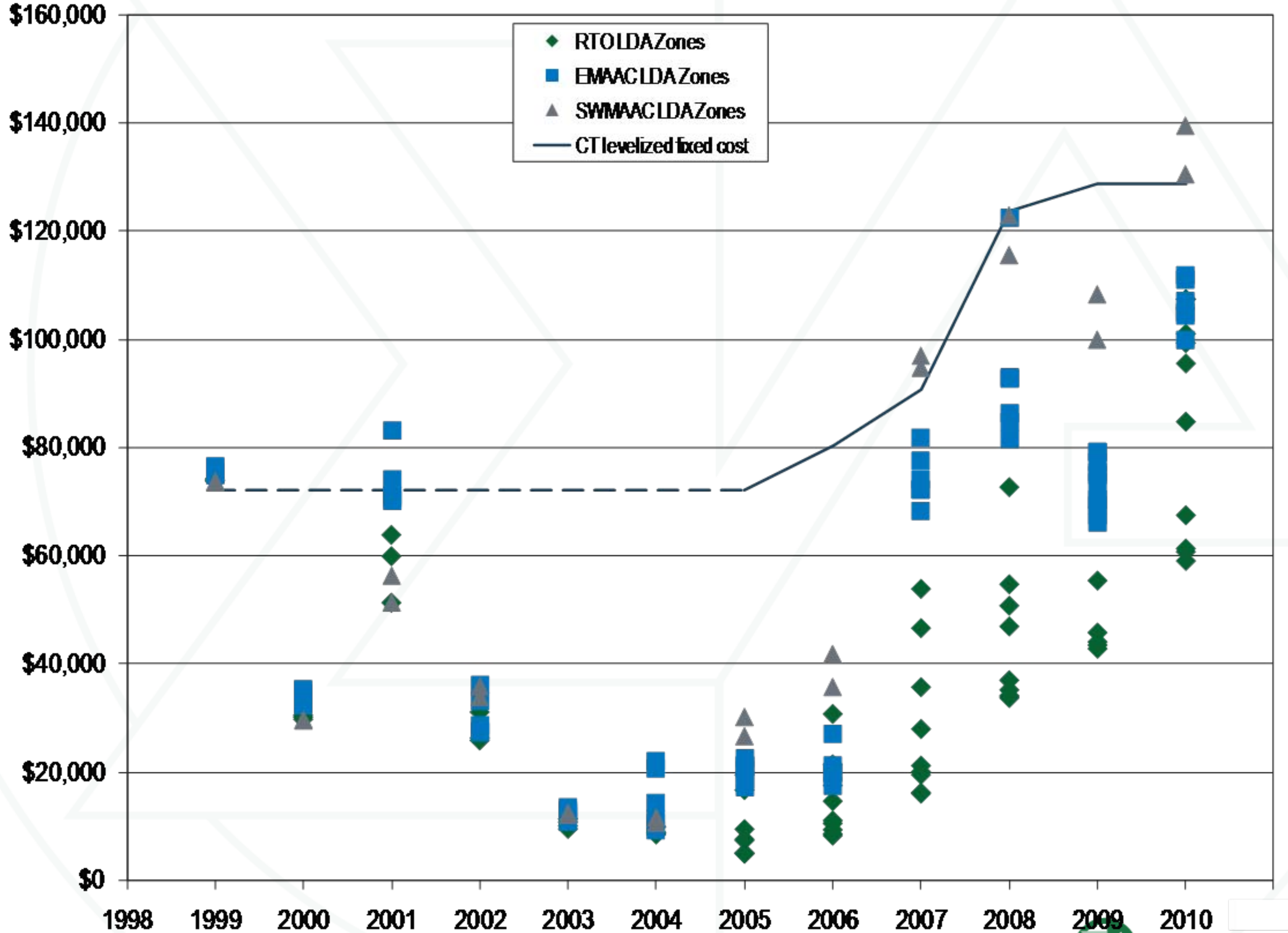

Figure 3-8 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010

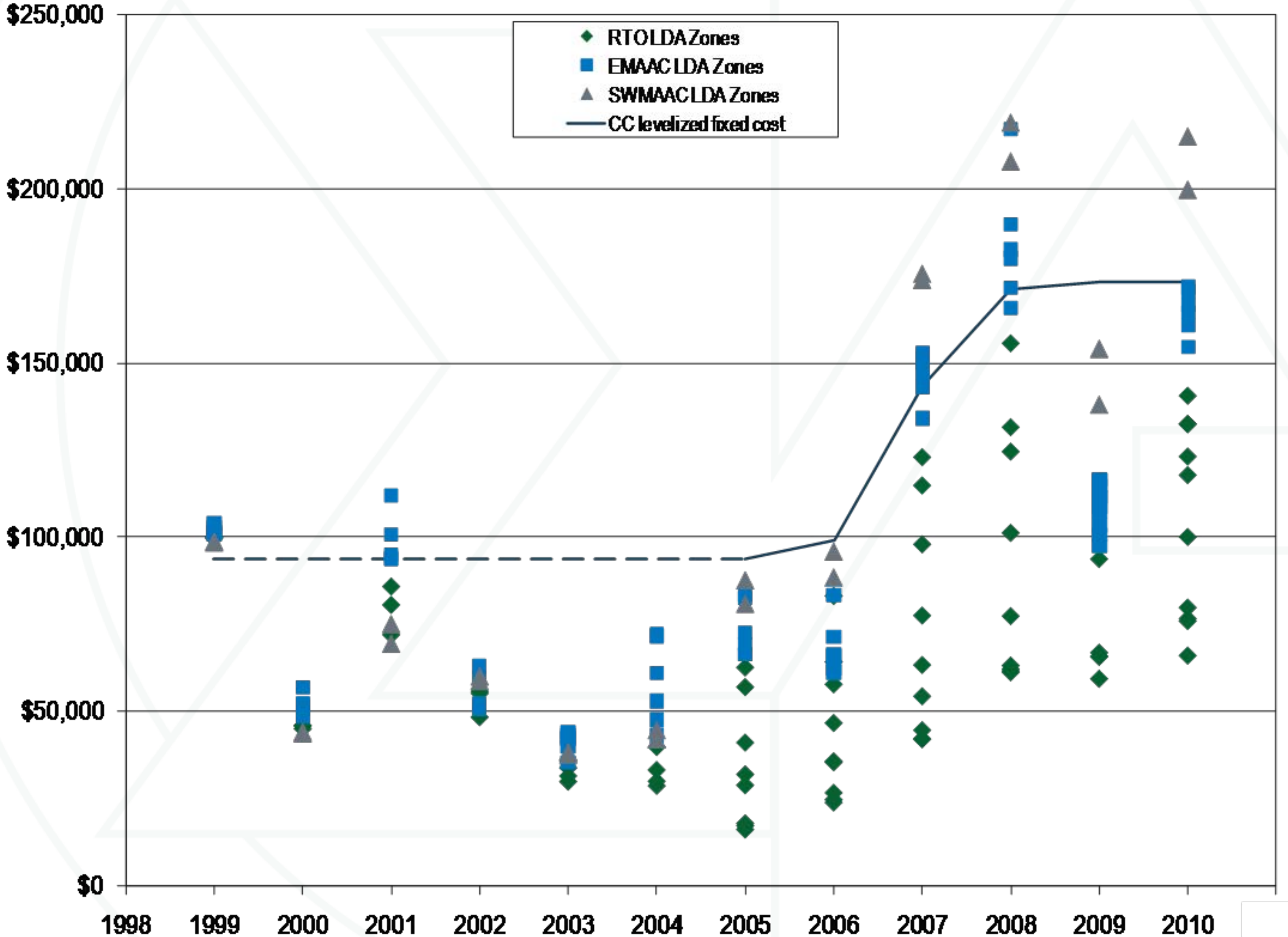

Figure 3-11 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010

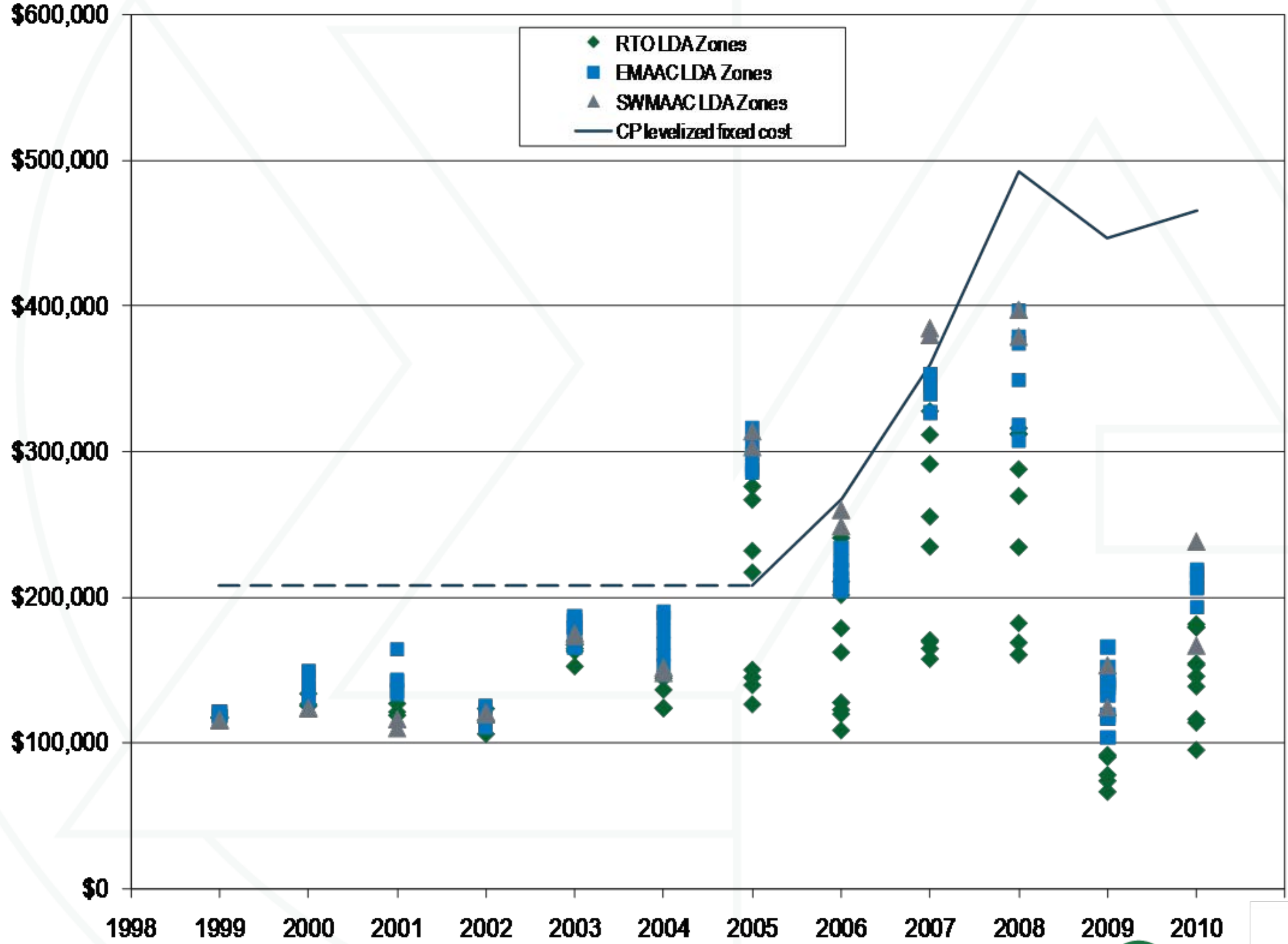

Table 3-36 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 and 2010

	2009		2010	
Technology	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	0%	100%	30%	100%
CC - Three on One Frame E Technology	54%	100%	85%	100%
CC - Two or Three on One Frame F Technology	83%	100%	93%	100%
CT - First & Second Generation Aero (P&W FT 4)	6%	100%	32%	100%
CT - First & Second Generation Frame B	2%	100%	22%	99%
CT - Second Generation Frame E	0%	100%	42%	100%
CT - Third Generation Aero (GE LM 6000)	16%	100%	32%	100%
CT - Third Generation Aero (P&W FT- 8 TwinPak)	0%	100%	33%	100%
CT - Third Generation Frame F	25%	100%	62%	100%
Diesel	12%	96%	13%	100%
Hydro	100%	100%	100%	100%
Nuclear	93%	100%	100%	100%
Oil or Gas Steam	3%	92%	3%	92%
Sub-Critical Coal	30%	75%	52%	82%
Super Critical Coal	35%	82%	50%	82%

Table 3-37 Profile of coal units not recovering avoidable costs from all PJM Market net revenues for 2010

Technology	Coal plants with full recovery of avoidable costs	Coal plants with less than full recovery of avoidable costs
Total Installed Capacity	37,808	6,769
Installed Capacity within MAAC	**12,978**	**6,021**
Avg. Installed Capacity (ICAP)	**282.1**	**225.6**
Avg. Age of Plant (Years)	40	50
Avg. Heat Rate (Btu/kWh)	**10,872**	**11,429**
Avg. Run Hours (Hours)	6,505	3,847
Avg. Avoidable Costs	**$61,748**	**$145,904**
Avg. Incremental Cost per MWh	$29.92	$43.08

Table 3-38 Installed capacity associated with various levels of avoidable cost recovery: Calendar year 2010

Groups of coal plants by percent recovery of avoidable cost	Installed Capacity (MW)	Percent of Total
0% - 65%	2,763	30.9%
65% - 75%	2,099	23.5%
75% - 90%	818	9.1%
90% - 100%	1,089	12.2%
100% - 115%	2,178	24.3%
Total	8,947	100.0%

Table 3-39 Units lacking controls for either NO_x emission rates, SO_2 emission rates, or both as of January 2010

Characteristics	Coal plants without NOx controls in place	Coal plants without SO2 controls in place	Coal plants without NOx and without SO2 controls in place	Total
Number of units	4	63	8	75
Total installed capacity (ICAP)	212	13,543	633	14,388

Table 3-41 Total installed capacity associated with estimated levels of additional revenue needed for recovery of project investment associated with environmental controls

Ranges of additional revenue needed ($/MW-day)	Installed capacity (ICAP) associated base case	Cumulative installed capacity (ICAP) associated with base case	Installed capacity (ICAP) associated with NO_x sensitivity	Cumulative installed capacity (ICAP) associated with NO_x sensitivity
$0	43	43	2,816	2,816
$1 - $99	**121**	**164**	**1,050**	**3,867**
$100 - $199	50	214	1,706	5,573
$200 - $299	**0**	**214**	**1,560**	**7,133**
$300 - $399	1,143	1,357	489	7,621
$400 - $499	**7,554**	**8,911**	**4,352**	**11,973**
$500 - $599	3,420	12,331	815	12,788
$600 - $799	**1,336**	**13,666**	**6,107**	**18,894**
$800 or greater	721	14,388	2,990	21,884

Figure 3-12 Total installed capacity associated with estimated levels of additional revenue needed for full project investment recovery in 2010

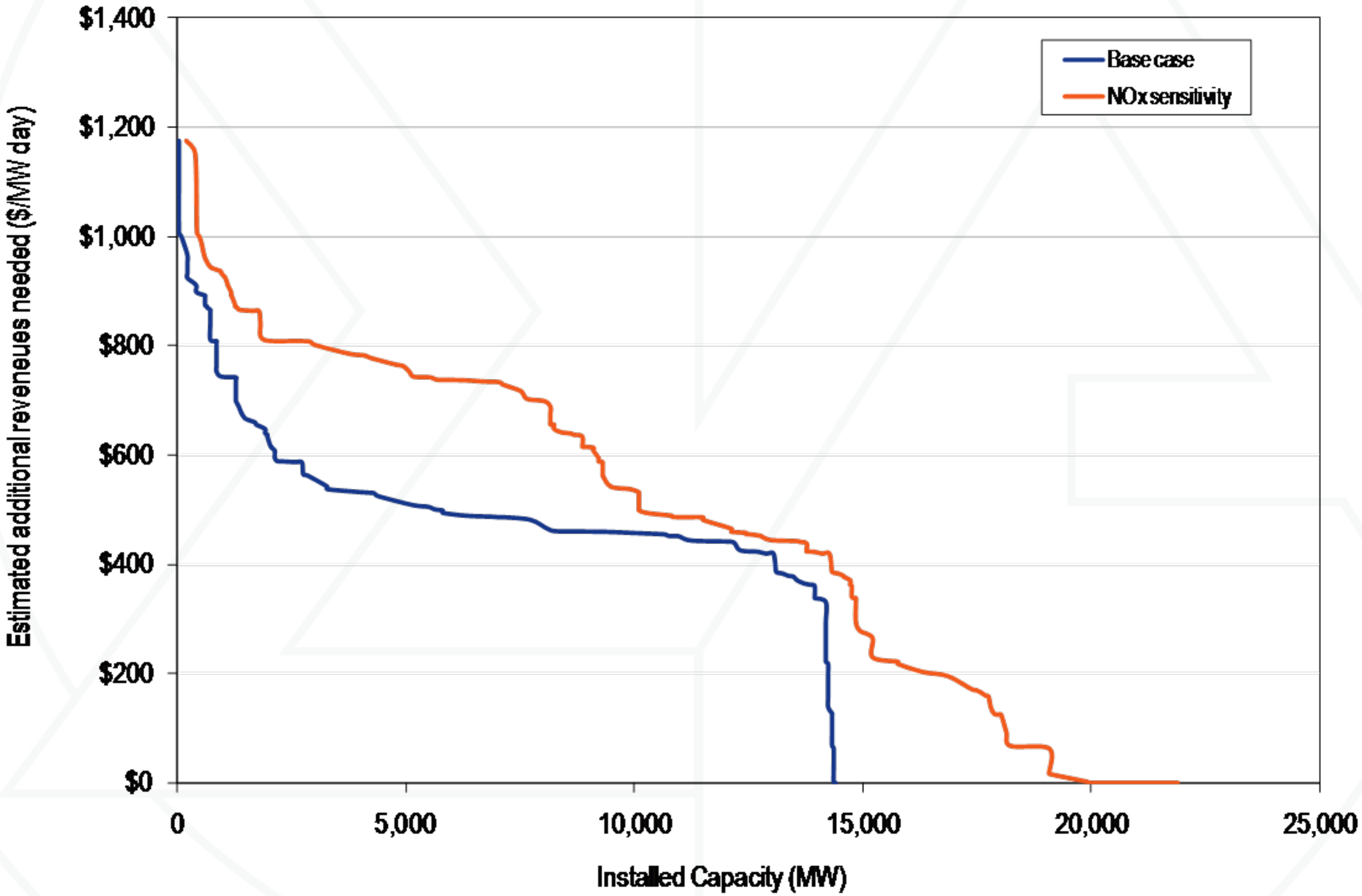

Table 2-72 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	**Capacity and Energy (Full option) or Capacity Only**	**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**	**Voluntary 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	**Full Option:** Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments. **Capacity only:** No energy payments	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payments applicable during PJM declared Emergency Events mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 2-22 Demand Response revenue by market: Calendar years 2002 through 2010

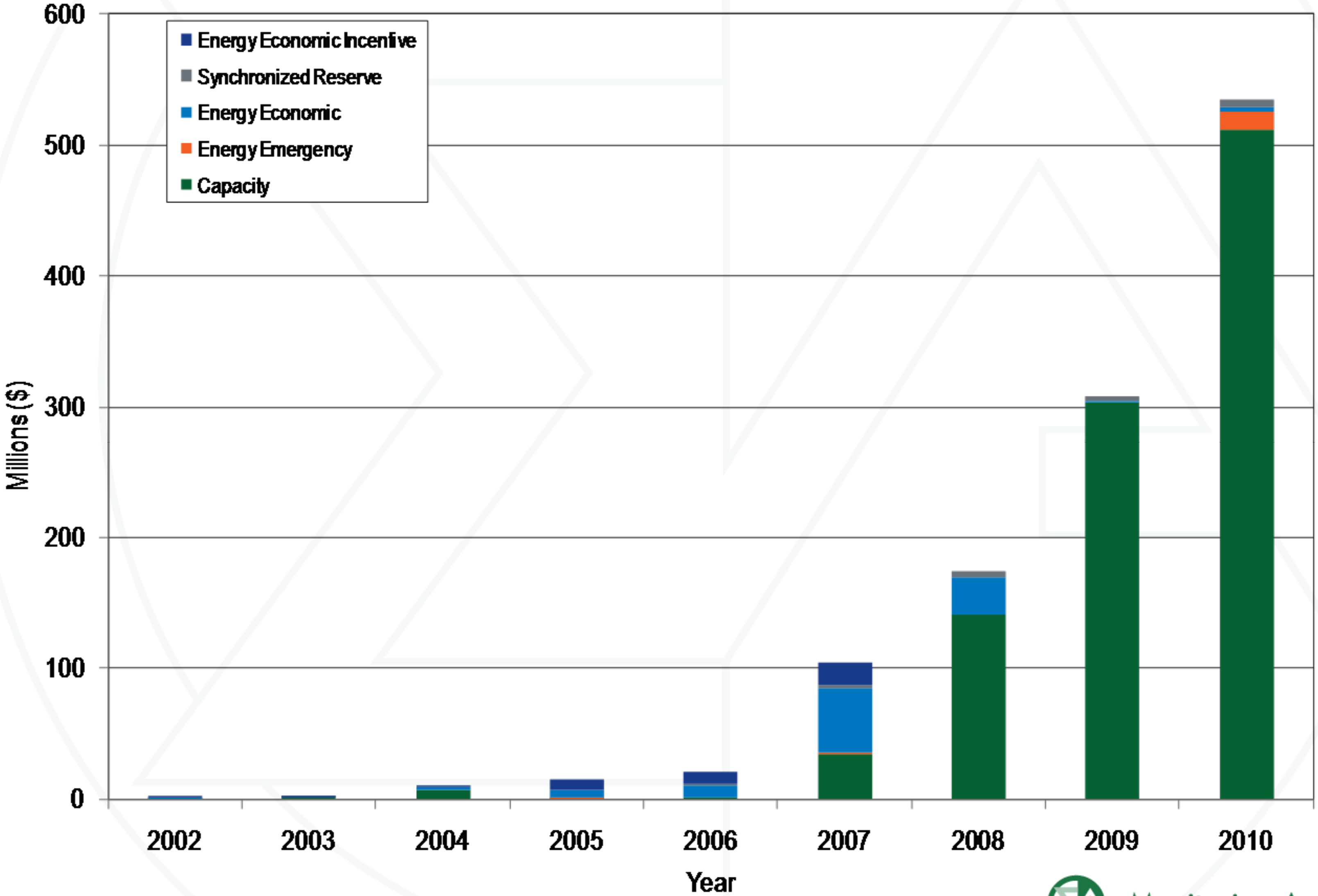

Table 2-84 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2010

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	**1,017.7**	**3,480.5**	**4,498.2**
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	**1,070.0**	**7,982.4**	**9,052.4**

Table 2-94 Distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for all events in the 2010/2011 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event days	Proportion of total GLD participant event days	Cumulative Proportion	Observed reductions (MW)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	1,929	50%	50%	483	15%	15%
25% - 50%	**643**	**17%**	**67%**	**618**	**19%**	**34%**
50% - 75%	406	11%	77%	447	14%	48%
75% - 100%	**323**	**8%**	**86%**	**360**	**11%**	**59%**
100% - 150%	306	8%	94%	429	13%	72%
150% - 200%	**80**	**2%**	**96%**	**294**	**9%**	**81%**
200% - 300%	71	2%	98%	378	12%	93%
300% or greater	**87**	**2%**	**100%**	**244**	**7%**	**100%**
Total	3,845	100%		3,252	100%	

Table 3-68 Operating reserve credits and charges

Credits Received For		Charges Paid By
Day ahead: Day-Ahead Energy Market Day-ahead import transactions	→	Day-ahead demand Decrement bids Day-ahead export transactions
Synchronous condensing	→	Real-time load Real-time export transactions
Balancing: Balancing energy market Lost opportunity cost Real-time import transactions	→	Real-time deviations from day-ahead schedules

Balancing Energy Market Credits Received (By RTO, Eastern Region, Western Region)		Balancing Energy Market Charges Paid By
Reliability Credits	→	Real-time load Real-time export transactions
Deviation Credits	→	Real-time deviations from day-ahead schedules

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Table 3-71 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2010

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.1201	42.3%	1.1100*	(47.5%)
2010	$569,062,688	74.6%	1.6%	0.1133	(5.7%)	2.3103*	108.1%

Table 3-73 Regional balancing charges allocation: Calendar year 2010

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$42,122,972	$1,689,055	$43,812,027	$102,864,673	$48,547,311	$32,906,726	$184,318,710	$228,130,737
	12.6%	0.5%	13.1%	30.7%	14.5%	9.8%	54.9%	68.0%
East	$46,474,131	$1,712,870	$48,187,002	$15,404,606	$6,727,200	$3,852,121	$25,983,926	$74,170,928
	13.9%	0.5%	14.4%	4.6%	2.0%	1.1%	7.7%	22.1%
West	$19,829,984	$862,677	$20,692,661	$6,916,779	$3,022,844	$2,577,253	$12,516,876	$33,209,536
	5.9%	0.3%	6.2%	2.1%	0.9%	0.8%	3.7%	9.9%
Total	$108,427,088	$4,264,602	$112,691,690	$125,186,058	$58,297,355	$39,336,099	$222,819,512	$335,511,201
	32.3%	1.3%	33.6%	37.3%	17.4%	11.7%	66.4%	100%

Figure 3-20 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): Calendar year 2010

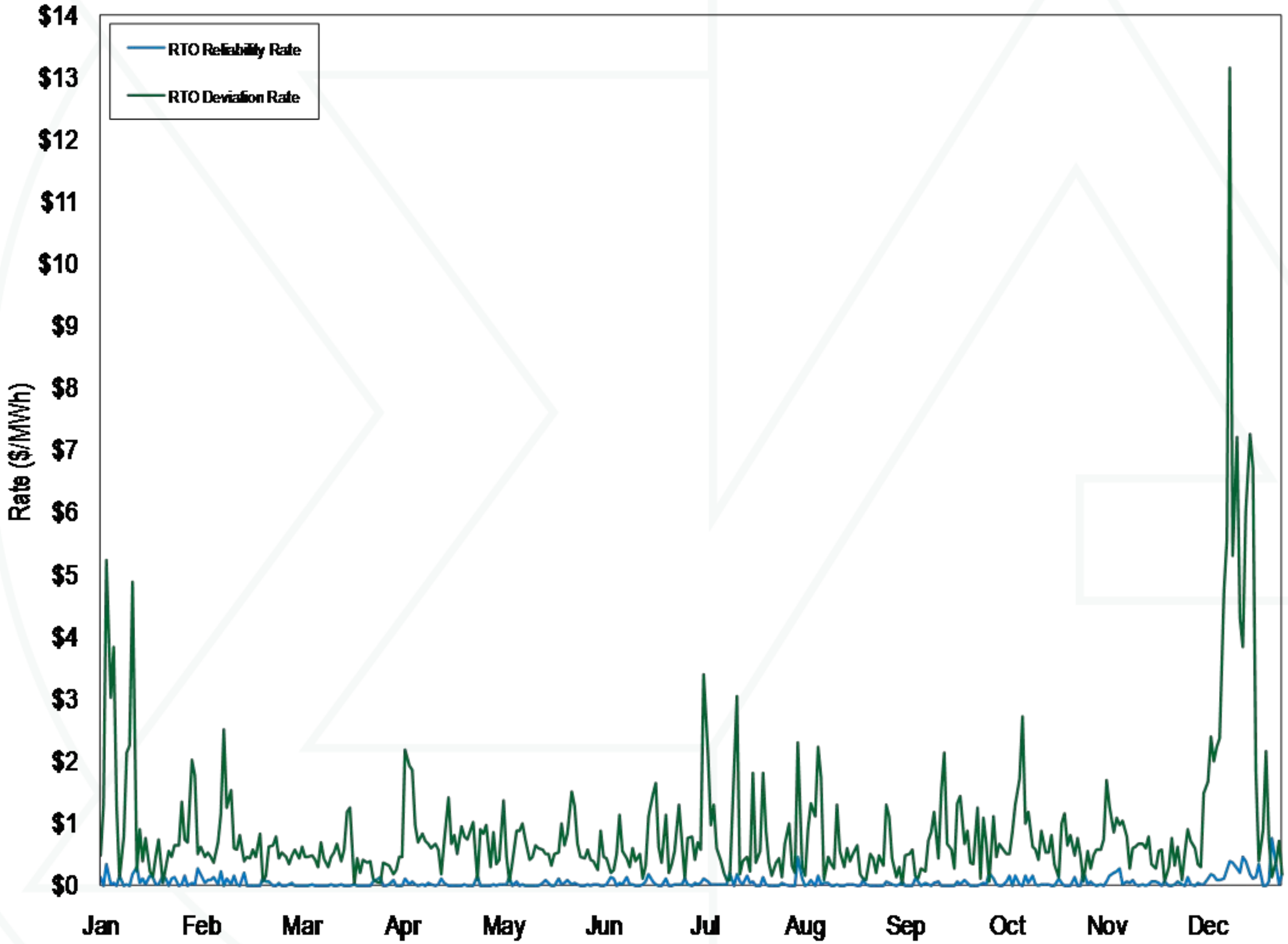

Figure 3-22 Operating reserve credits: Calendar year 2010

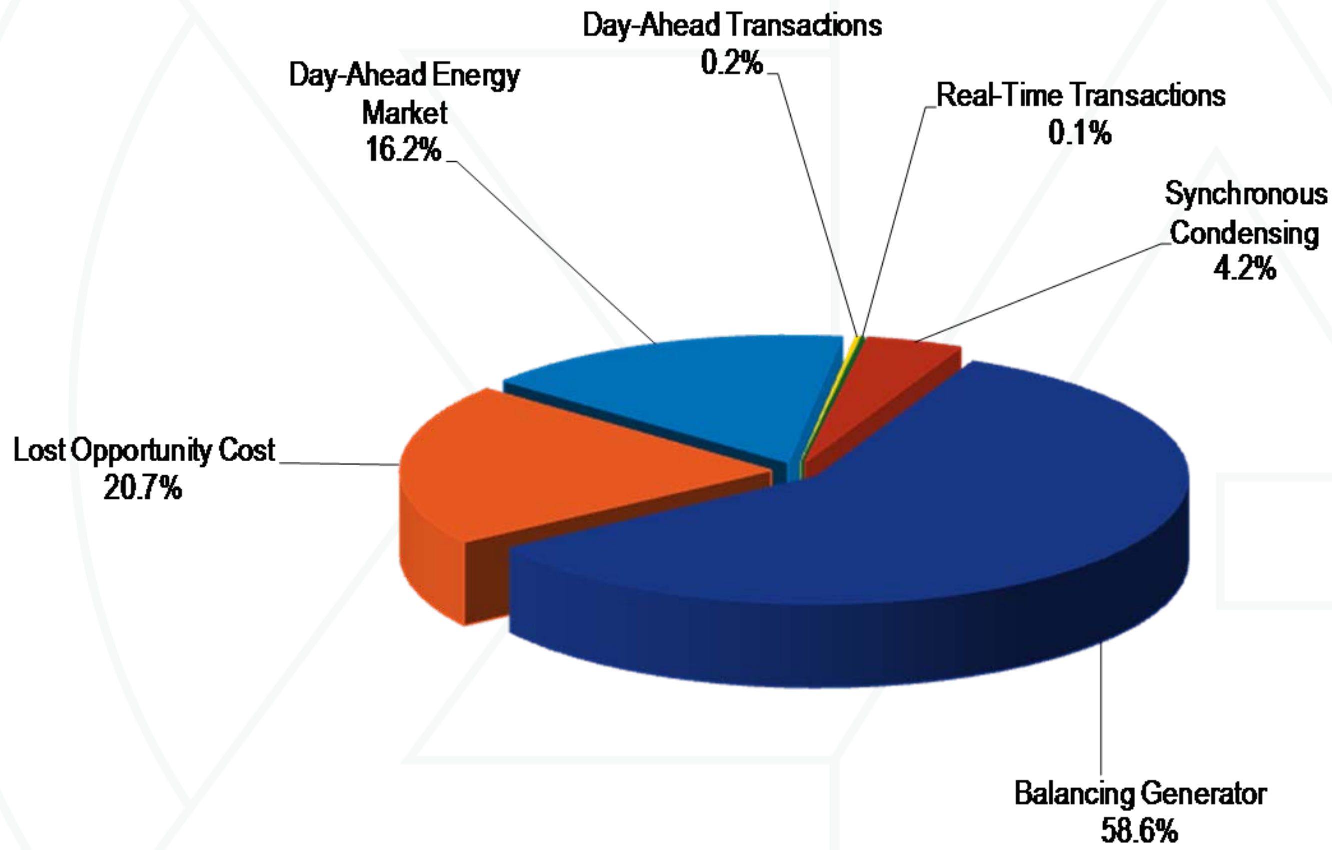

Table 3-90 Difference in total operating reserve charges between old rules and new rules: Calendar year 2010

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$189,747,902	$87,982,658	$57,780,641	$335,511,201
Charges (Current)	$108,427,088	$4,264,602	$112,691,690	$125,186,058	$58,297,355	$39,336,099	$222,819,512
Difference	$108,427,088	$4,264,602	$112,691,690	($64,561,844)	($29,685,303)	($18,444,542)	($112,691,690)

Table 3-92 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2010

Month	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)
Feb	$5,319,874	$3,936,420	($1,383,454)
Mar	$4,797,076	$3,468,829	($1,328,248)
Apr	$6,480,725	$5,301,308	($1,179,417)
May	$13,658,944	$10,158,307	($3,500,637)
Jun	$18,021,960	$10,673,612	($7,348,348)
Jul	$17,068,724	$14,327,987	($2,740,737)
Aug	$9,394,993	$7,575,980	($1,819,013)
Sep	$13,065,704	$10,820,010	($2,245,694)
Oct	$9,019,721	$6,456,368	($2,563,353)
Nov	$5,817,780	$3,925,450	($1,892,330)
Dec	$17,570,579	$19,884,462	$2,313,884
Total	$132,741,464	$106,719,600	($26,021,864)

Table 3-94 Impact of segmented make whole payments: December 2008 through December 2010

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
2010	Jan	$32,982,105	$33,924,489	$942,385
2010	Feb	$17,321,317	$17,609,133	$287,815
2010	Mar	$13,458,120	$13,672,172	$214,052
2010	Apr	$16,441,644	$17,036,058	$594,414
2010	May	$21,854,306	$23,455,721	$1,601,415
2010	Jun	$36,297,521	$38,885,349	$2,587,828
2010	Jul	$32,251,623	$37,053,630	$4,802,007
2010	Aug	$21,867,024	$24,335,171	$2,468,147
2010	Sep	$24,293,196	$25,686,790	$1,393,593
2010	Oct	$21,839,101	$22,478,455	$639,354
2010	Nov	$15,795,391	$16,238,383	$442,991
2010	Dec	$49,180,164	$51,293,810	$2,113,646
Total		$502,883,559	$529,145,613	$26,262,054

Table 3-99 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2010

	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%

Table 3-110 Annual balancing transaction credits: 2000 through 2010

Year	Balancing Transaction Credit
2000	$0
2001	$0
2002	$98,065
2003	$0
2004	$1,146
2005	$857,550
2006	$8,826
2007	$966,213
2008	$827,633
2009	$91,293
2010	$23,092,640

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2010

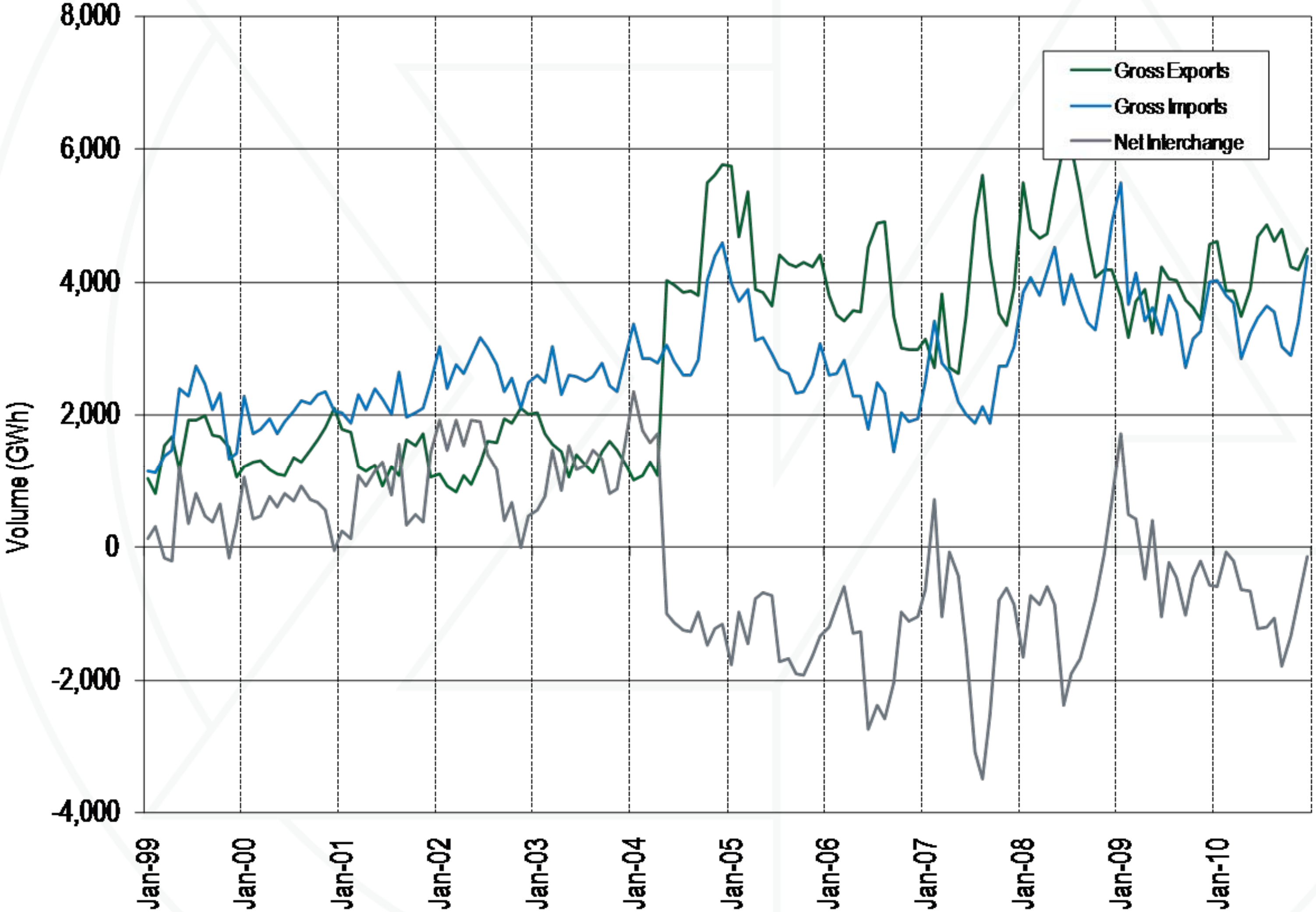

Figure 4-4 PJM's footprint and its external interfaces

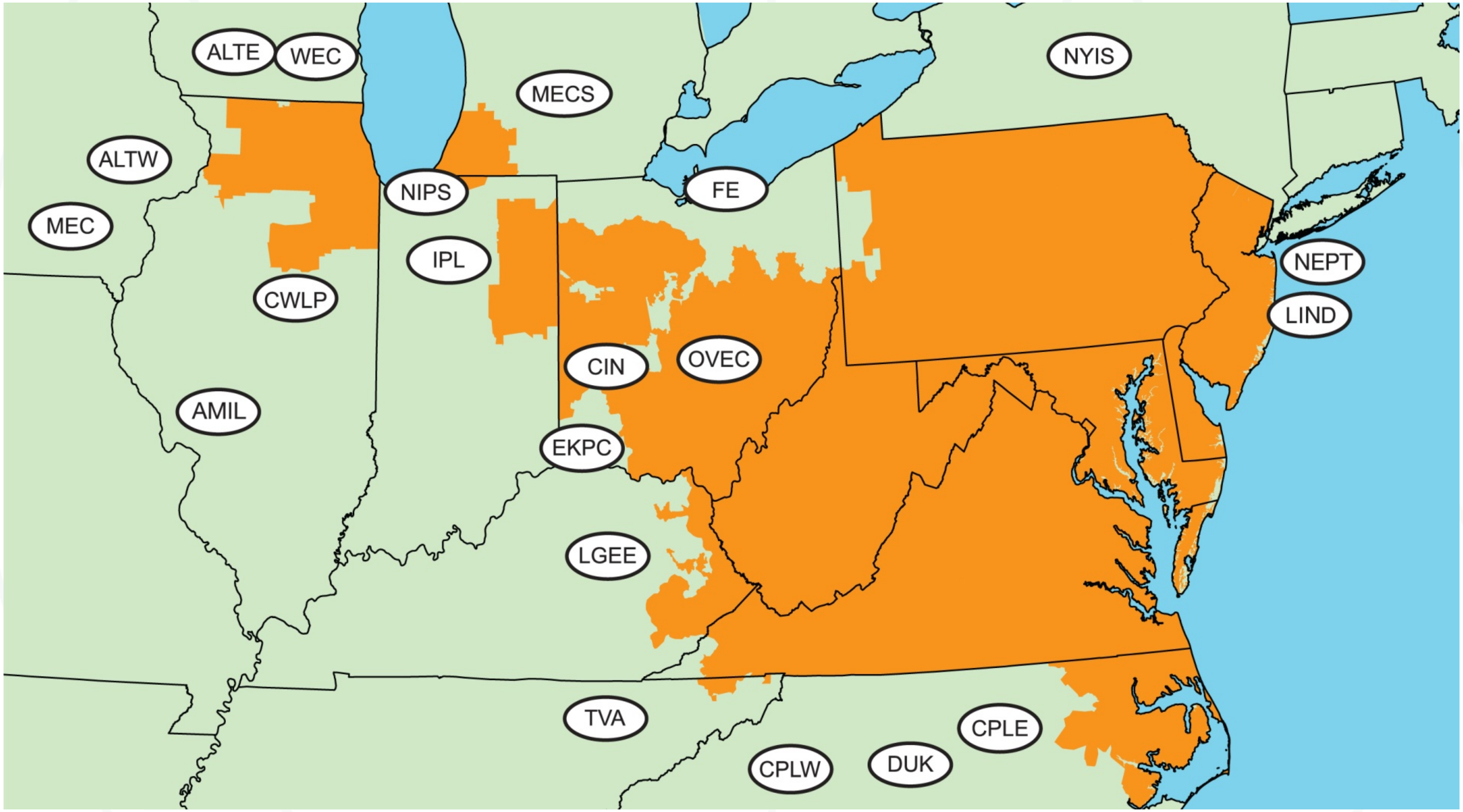

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2010

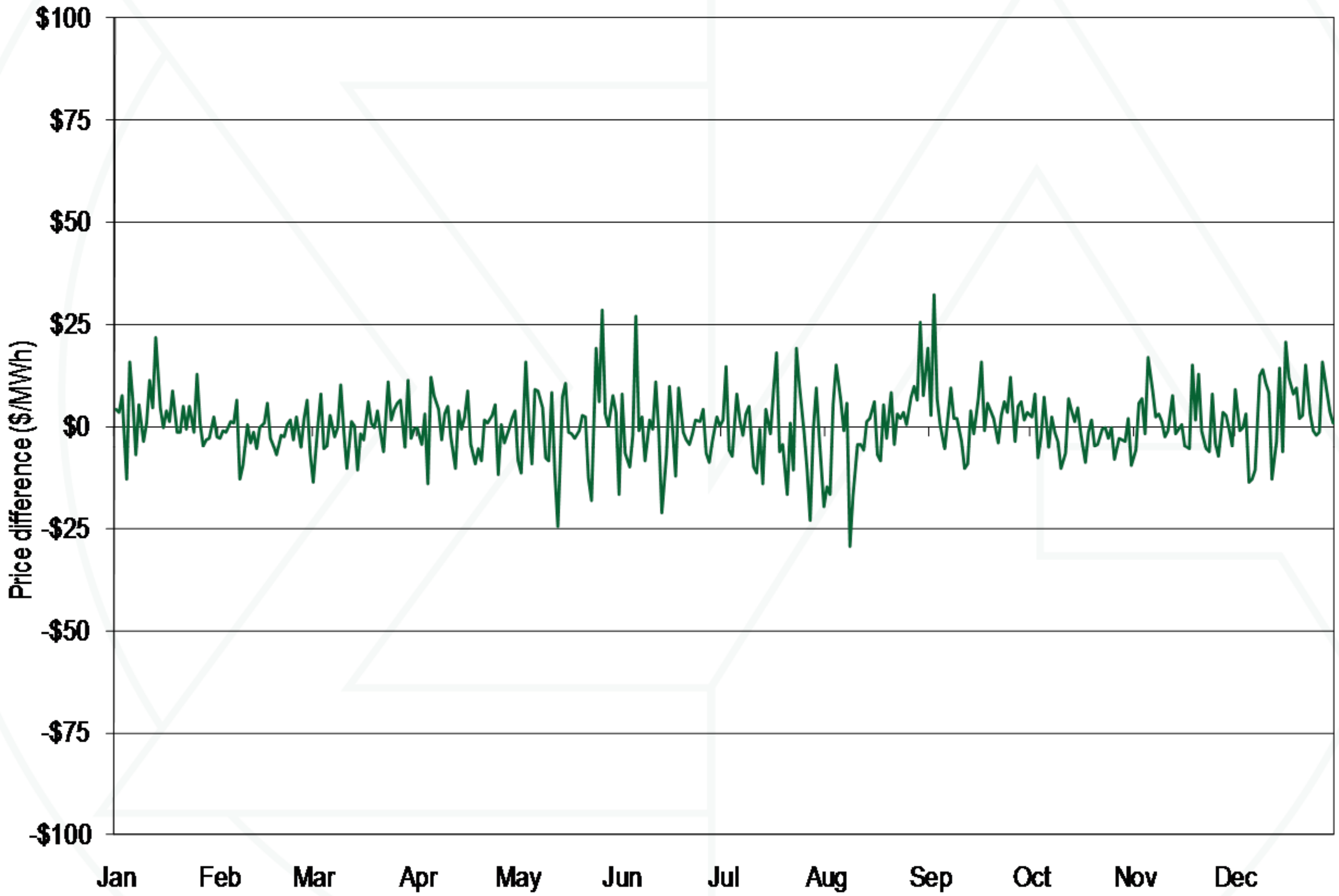

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2010

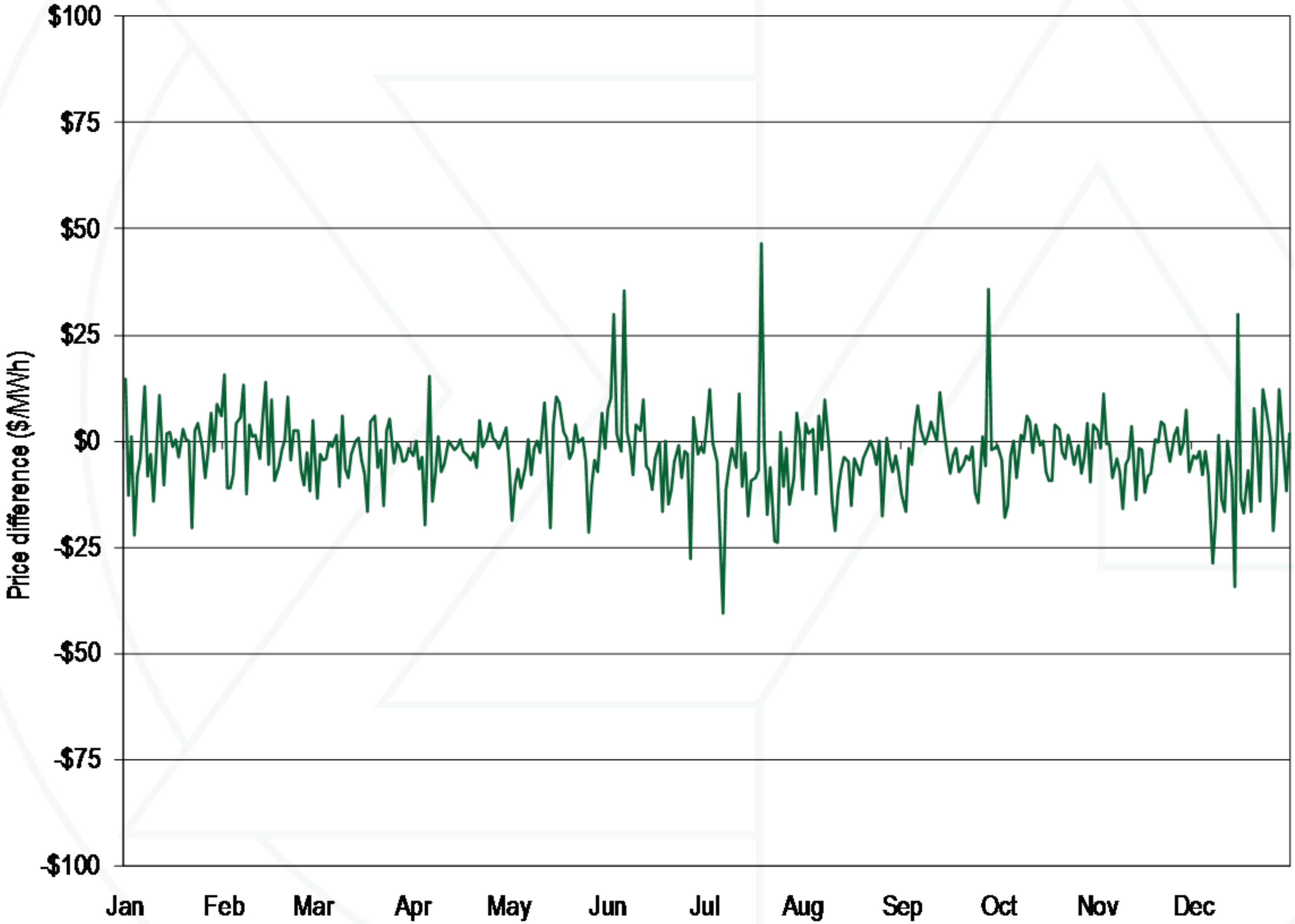

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2010

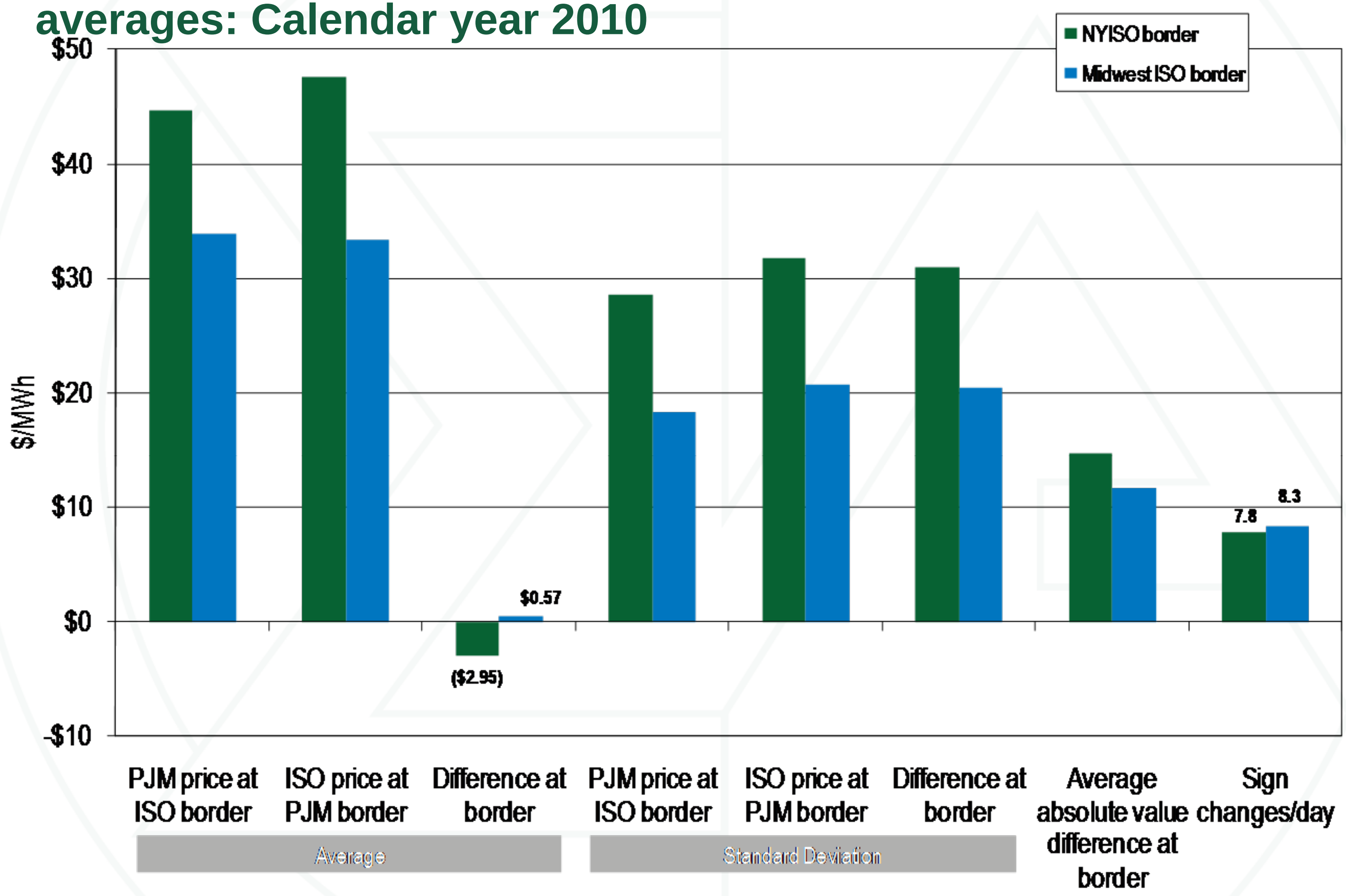

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Figure 5-1 History of capacity prices: Calendar year 1999 through 2013

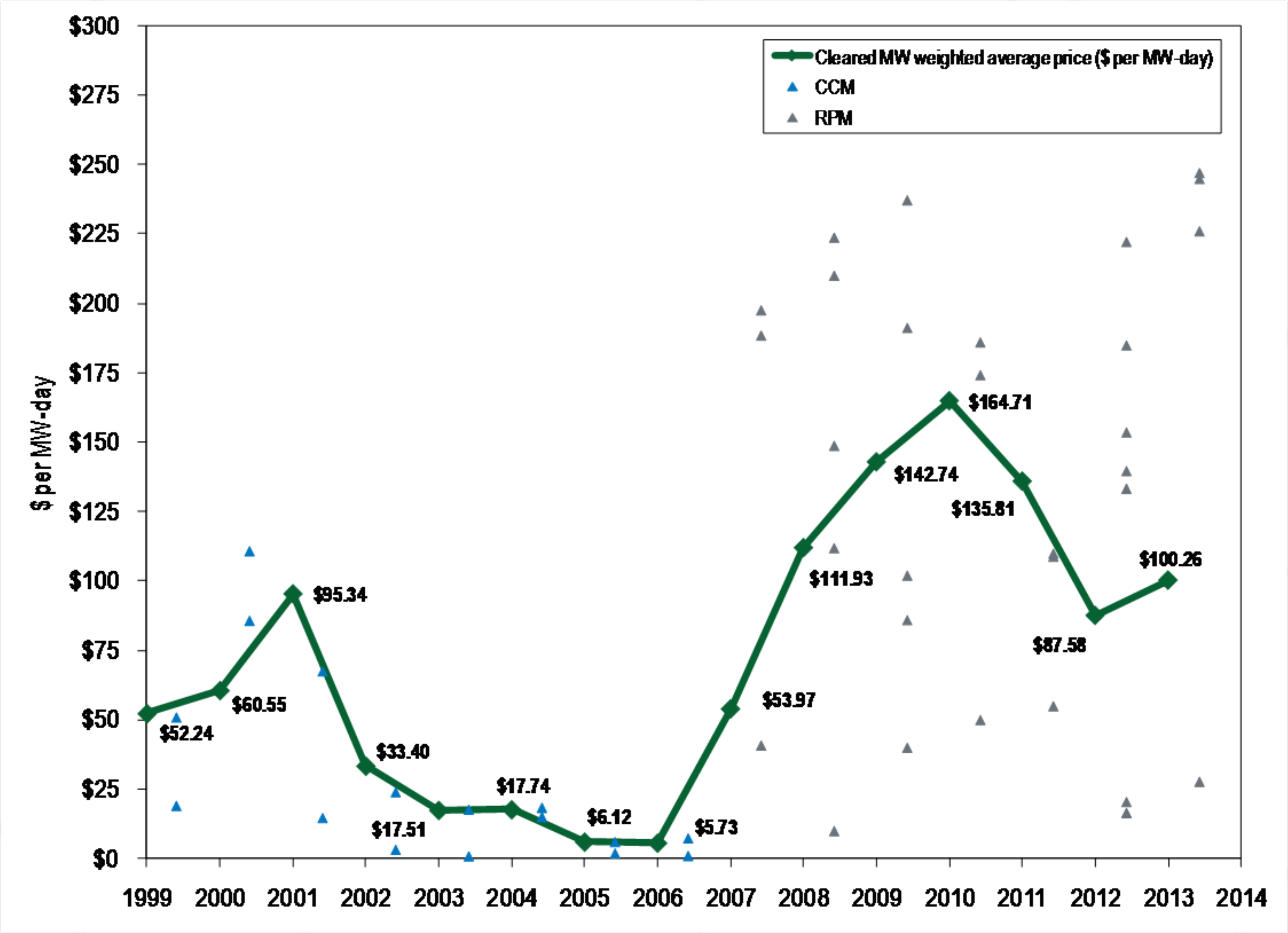

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Figure 5-5 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2010

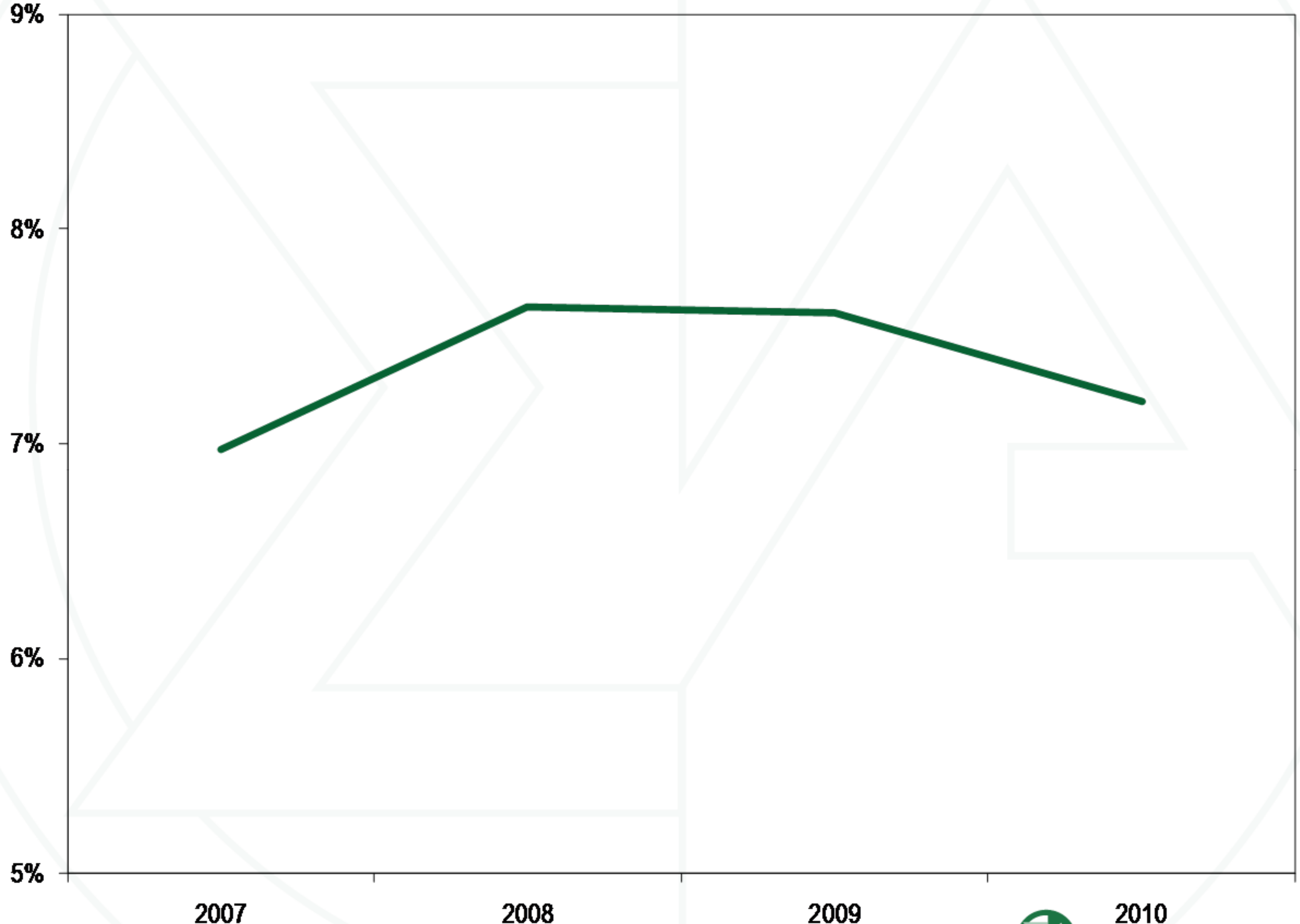

Table 5-26 PJM EFORd vs. XEFORd: Calendar year 2010

	2010 EFORd	2010 XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.1%
Combustion Turbine	8.8%	6.9%	1.9%
Diesel	6.5%	4.5%	2.0%
Hydroelectric	1.2%	0.9%	0.3%
Nuclear	2.5%	2.5%	0.0%
Steam	9.8%	8.5%	1.3%
Total	7.2%	6.2%	1.0%

Table 6-4 History of ancillary services costs per MW of Load: 2001 through 2010

Year	Regulation	Scheduling, System Control, and Dispatch	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22		$1.08
2002	$0.46	$0.54	$0.22	$0.00	$0.74
2003	$0.50	$0.62	$0.24	$0.16	$0.86
2004	$0.50	$0.62	$0.26	$0.12	$0.92
2005	$0.80	$0.50	$0.26	$0.12	$0.96
2006	$0.52	$0.52	$0.30	$0.08	$0.44
2007	$0.64	$0.52	$0.30	$0.06	$0.62
2008	$0.71	$0.39	$0.32	$0.08	$0.62
2009	$0.34	$0.32	$0.36	$0.05	$0.48
2010	$0.35	$0.38	$0.40	$0.07	$0.74

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through December 2010

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
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%

Table 6-13 Summary of changes to Regulation Market design

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

Table 6-18 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through December 2010

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	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%

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010	$1,428	99%	$34,771	4%
Total	$9,591		$185,358	5%

Figure 7-1 Map of “Backbone” Projects*

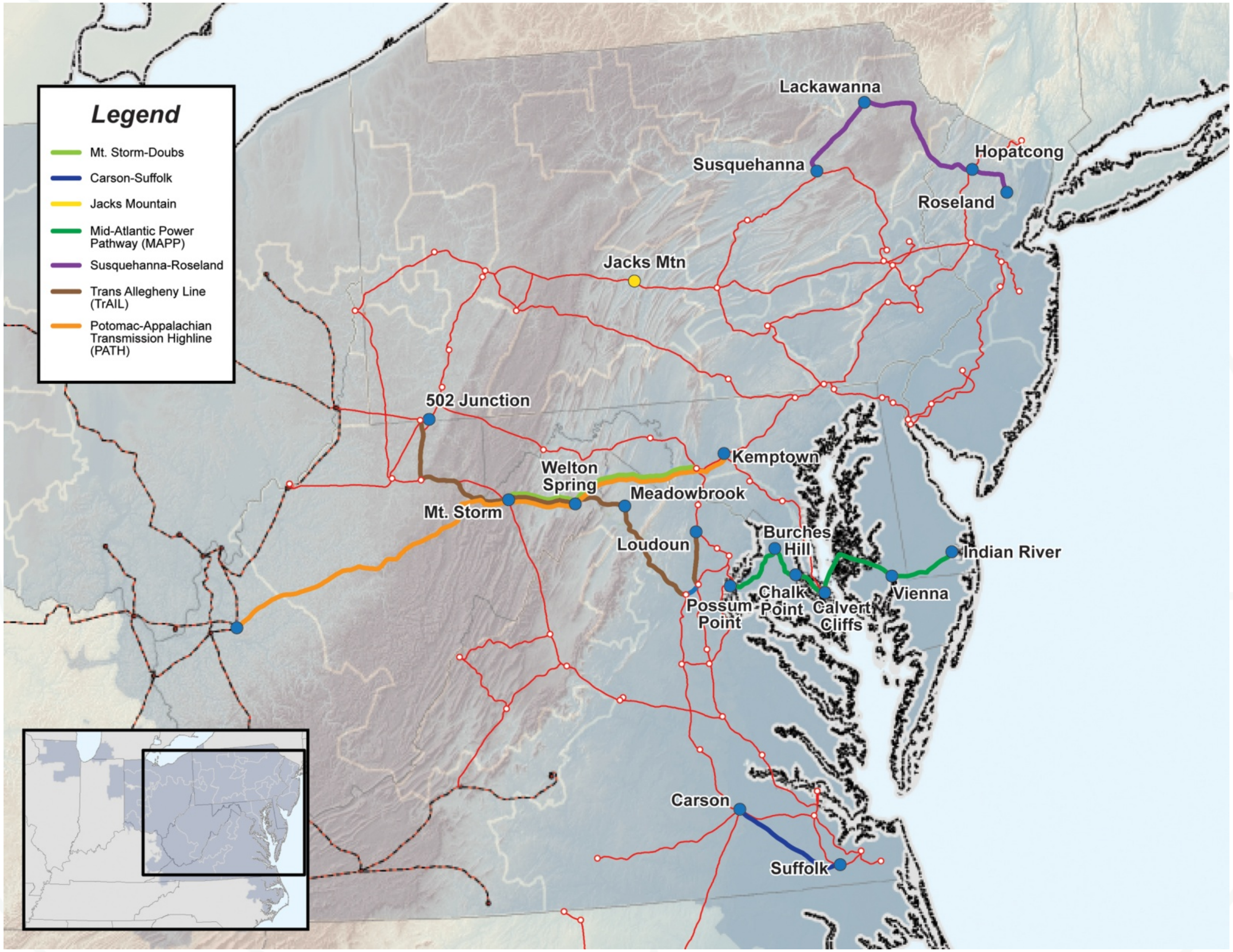

Table 8-10 Comparison of self scheduled FTRs: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	**68,589**	**109,612**	**62.6%**
2010/2011	55,732	102,046	54.6%

Figure 8-9 FTR payout ratio by month: June 2003 to December 2010

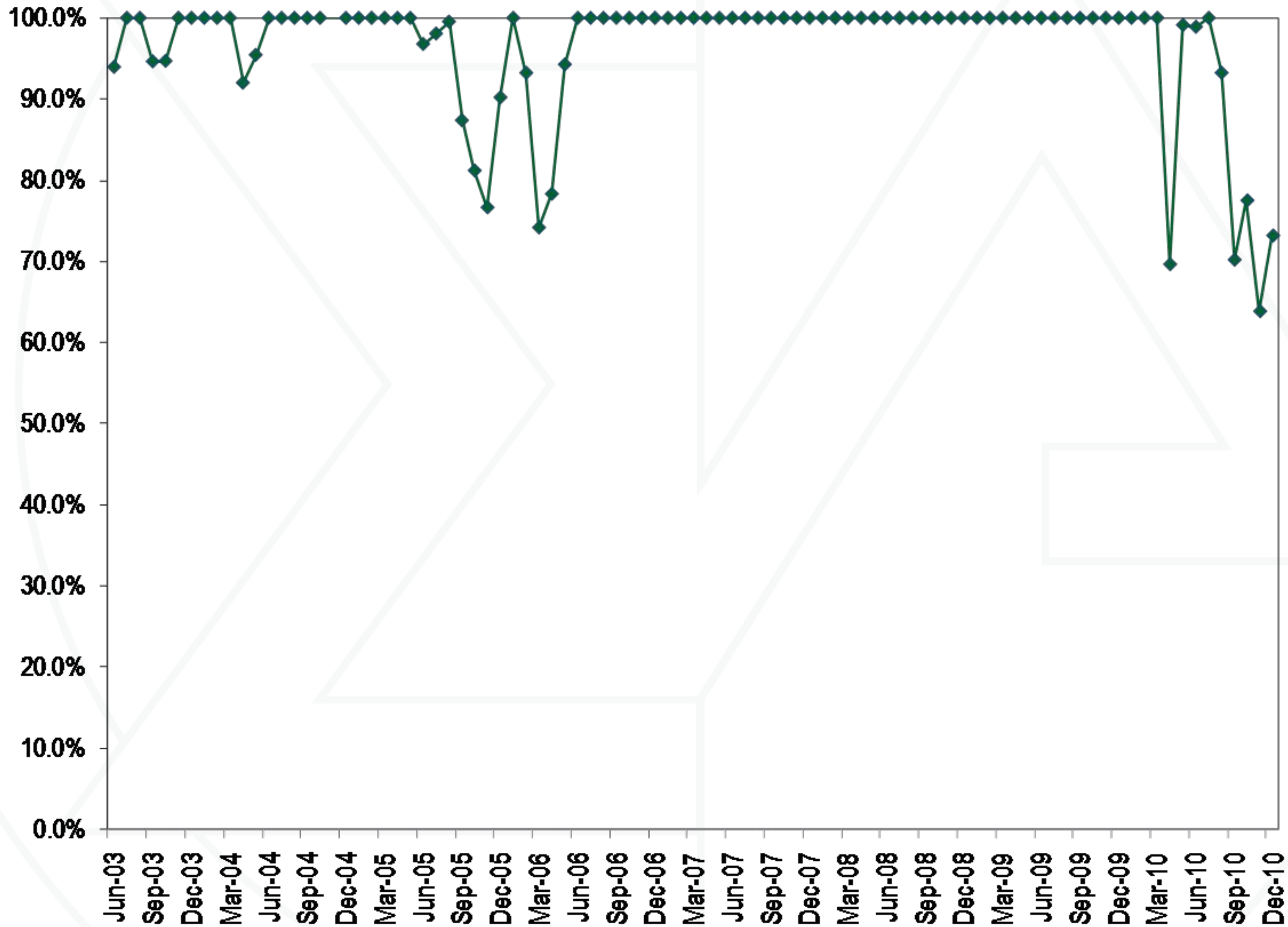

Table 8-32 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,721	$25,540,714	($2,067,671)	$10,817,043	($12,884,714)	0.0%
AEP	$223,262,229	$157,919,018	$214,898,039	$166,283,208	$101,031,029	$65,252,179	>100%
AP	$365,048,488	$185,774,650	$324,136,428	$226,686,710	$132,996,453	$93,690,257	>100%
BGE	$52,131,739	$29,778,076	$34,611,142	$47,298,673	$40,787,754	$6,510,919	>100%
ComEd	$27,261,279	$61,701,901	$12,504,362	$76,458,818	$192,953,092	($116,494,274)	39.6%
DAY	$7,505,314	$1,208,852	($146,827)	$8,860,993	$7,993,310	$867,683	>100%
DLCO	$2,454,337	$10,773,597	($3,631,769)	$16,859,703	$25,084,077	($8,224,374)	67.2%
Dominion	$213,840,239	$156,718,198	$240,575,877	$129,982,560	$150,288,685	($20,306,125)	86.5%
DPL	$18,915,429	$13,281,446	$38,621,277	($6,424,402)	$28,398,375	($34,822,777)	0.0%
JCPL	$34,924,192	($890,074)	$44,362,866	($10,328,748)	$18,958,788	($29,287,536)	0.0%
Met-Ed	$27,312,021	$15,468,233	$35,876,903	$6,903,351	$4,609,666	$2,293,685	>100%
PECO	$49,863,646	$21,467,430	$56,377,913	$14,953,163	($22,617,637)	$37,570,800	>100%
PENELEC	$49,412,326	$61,808,839	$63,892,689	$47,328,476	$58,884,119	($11,555,643)	80.4%
Pepco	$23,702,306	$111,232,601	$102,336,490	$32,598,417	$66,040,760	($33,442,343)	49.4%
PJM	$9,979,482	($4,934,756)	($3,846,501)	$8,891,227	$8,551,453	$339,774	>100%
PPL	$55,143,860	$21,032,754	$65,711,467	$10,465,147	($8,203,127)	$18,668,274	>100%
PSEG	$94,609,270	$34,463,423	$119,797,997	$9,274,696	($1,140,092)	$10,414,788	>100%
RECO	($41,455)	($1,186,779)	($2,875,400)	$1,647,166	$1,562,712	$84,454	>100%
Total	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%

Table 8-33 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2009/2010	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%
2010/2011*	**$603,465,391**	**$804,051,163**	**$640,632,851**	**$766,883,703**	**$974,618,985**	**($207,735,282)**	**78.7%**

* Shows seven months ended 31-Dec-10

Table 8-34 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$11,331,731	($1,253,200)	$10,078,531	$648,843,903	1.6%
AEP	$197,171,258	$19,086,147	$216,257,405	$5,446,688,183	4.0%
AP	$374,775,181	$1,694,199	$376,469,380	$2,236,317,432	16.8%
BGE	$41,961,361	$34,967,124	$76,928,485	$2,028,384,691	3.8%
ComEd	$70,826,510	$29,508,528	$100,335,037	$3,654,271,600	2.7%
DAY	$7,144,529	($27,716)	$7,116,813	$690,554,201	1.0%
DLCO	$3,976,605	$17,232,438	$21,209,043	$583,038,268	3.6%
Dominion	$247,160,002	$21,337,739	$268,497,741	$5,445,331,798	4.9%
DPL	$15,793,341	$1,609,810	$17,403,150	$1,063,993,554	1.6%
JCPL	$24,705,469	($678,592)	$24,026,877	$1,340,425,345	1.8%
Met-Ed	$15,378,117	$11,053,779	$26,431,896	$818,645,514	3.2%
PECO	$37,079,205	$5,585,082	$42,664,287	$2,257,763,964	1.9%
PENELEC	$30,547,049	$36,419,581	$66,966,631	$791,735,853	8.5%
Pepco	$23,617,240	$39,947,933	$63,565,173	$1,898,879,568	3.3%
PJM	$17,311,724	$413,799	$17,725,523	NA	NA
PPL	$25,599,188	($253,197)	$25,345,991	$2,113,296,887	1.2%
PSEG	$63,669,715	($9,370,259)	$54,299,456	$2,562,025,594	2.1%
RECO	$37,522	$589,661	$627,183	$84,770,663	0.7%
Total	$1,208,085,747	$207,862,855	$1,415,948,602	$33,717,296,942	4.2%

Market Monitoring Unit

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