2009 State of the Market Report for PJM: Overview

Monitoring Analytics, LLC
Independent Market Monitor for PJM

Members Committee
March 25, 2010

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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

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, 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.

State of the Market Conclusions - 2009

- Energy Market results were competitive
- Capacity Market results were competitive
- Regulation Market results were not competitive
- Synchronized Reserve Markets' results were competitive
- Day Ahead Scheduling Reserve Market results were competitive
- FTR Market results were competitive

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State of the Market Recommendations – New Action

- 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 – New Action

- **Modification of regulation market rules**
  - **Modify opportunity cost calculation**
  - **Modify regulation offset against operating reserves**
- **Implementation of new scarcity pricing rules**
  - **Maximum price of $1,000**
  - **Offset mechanism with capacity market**
- **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**

State of the Market Recommendations – Continued Action

- **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.**
- **Retention and application of the improved local market power mitigation rules**
- **Retention and application of the improved market power mitigation rules in the regulation market**

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State of the Market Recommendations – Continued Action

- **Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power**
- **Retention of the market power mitigation rules included in PJM's Reliability Pricing Model (RPM) Tariff**
- **Retention and application of enhancements to PJM's rules governing operating reserve credits**
- **Continued enhancement of mechanisms used to manage prices and flows at interfaces with external areas.**

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Figure A-1 PJM's footprint and its 17 control zones

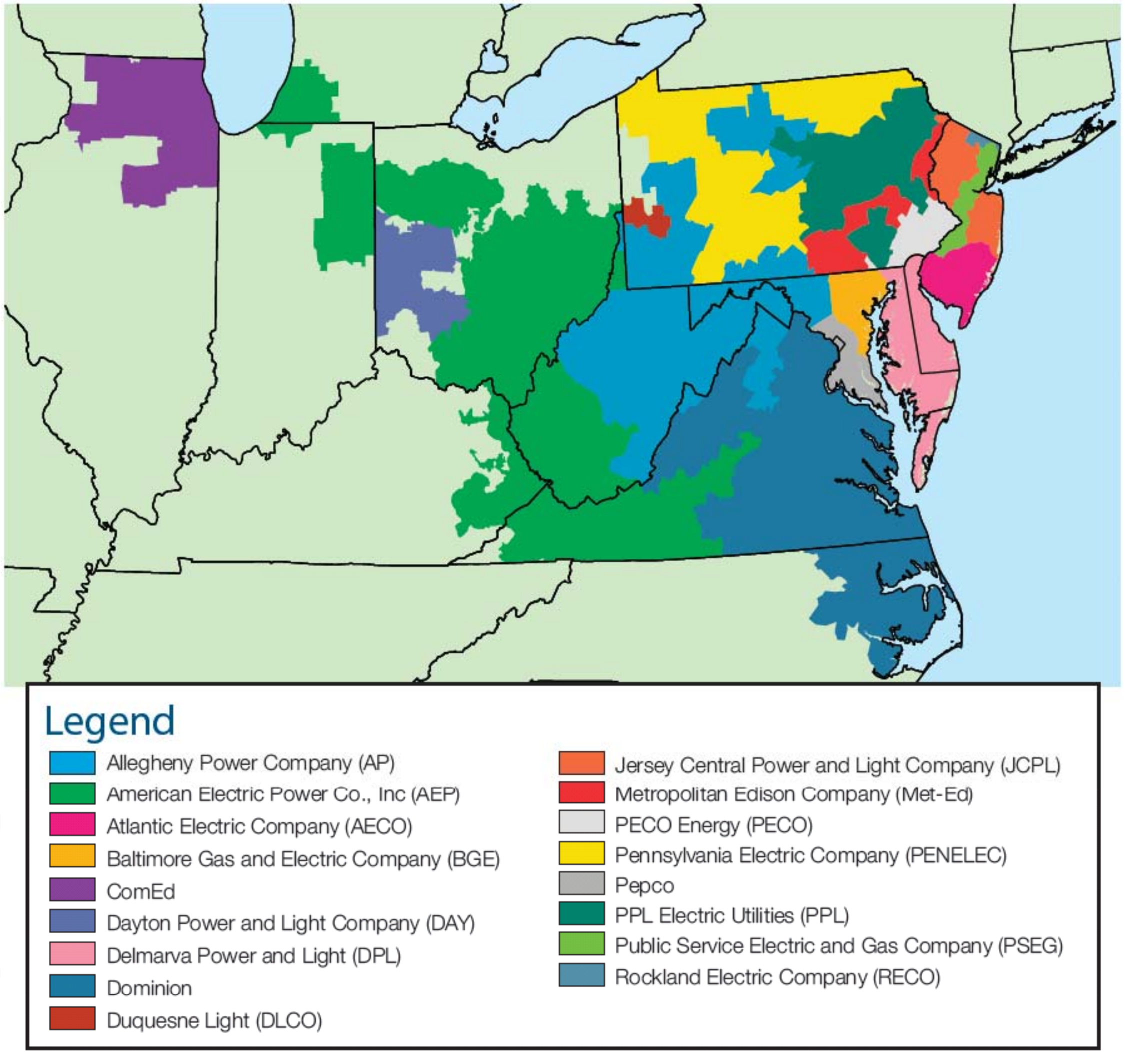

Table 1-1 Total price per MWh: Calendar year 2009

Category	$/MWh	Percent
Load Weighted Energy	$39.05	70.2%
Capacity	$10.75	19.3%
Transmission Service Charges	$4.00	7.2%
Operating Reserve (Uplift)	$0.49	0.9%
Reactive	$0.36	0.7%
Regulation	$0.34	0.6%
PJM Administrative Fees	$0.31	0.5%
Transmission Enhancement Cost Recovery	$0.09	0.2%
Transmission Owner (Schedule 1A)	$0.08	0.2%
Synchronized Reserves	$0.05	0.1%
Black Start	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
NERC/RFC	$0.01	0.0%
Load Response	$0.00	0.0%
Transmission Facility Charges	$0.00	0.0%
Total	$55.58	100.0%

Figure 2-1 Average PJM aggregate supply curves: Summers 2008 and 2009

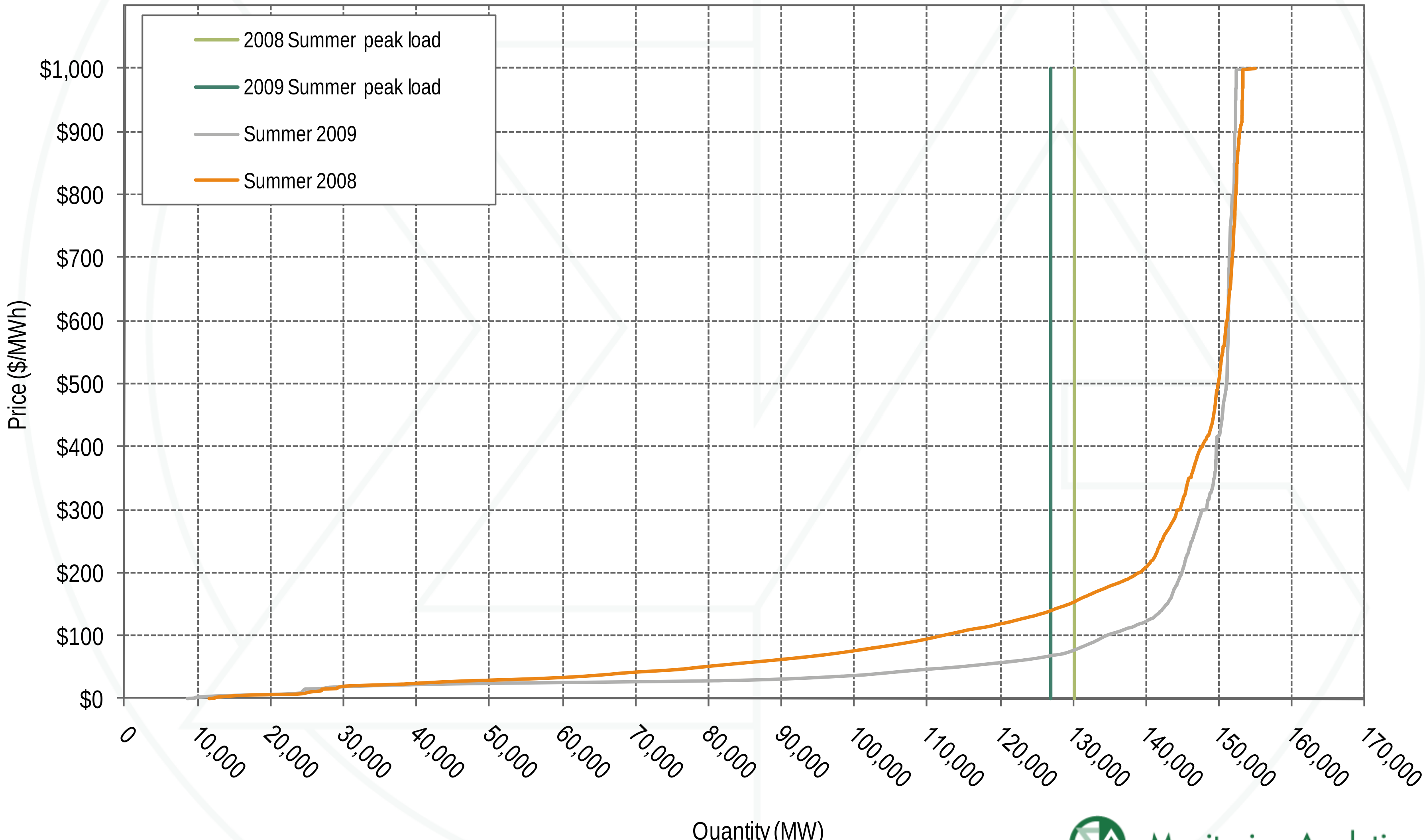

Table 3-36 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2009

	1-Jan-09		31-May-09		1-Jun-09		31-Dec-09	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%	68,137.1	40.7%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%	48,838.8	29.2%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%	30,731.5	18.4%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%	672.1	0.4%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%	306.9	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%	167,326.4	100.0%

Table 3-37 PJM generation (By fuel source (GWh)): Calendar year 2009

		GWh	Percent
Coal		349,818.2	50.5%
Nuclear		249,392.3	36.0%
Gas		67,218.9	9.7%
	Natural Gas	65,848.2	9.5%
	Landfill Gas	1,368.5	0.2%
	Biomass Gas	2.2	0.0%
Hydroelectric		14,123.0	2.0%
Waste		5,664.7	0.8%
	Solid Waste	4,147.0	0.6%
	Miscellaneous	1,517.7	0.2%
Wind		5,489.7	0.8%
Oil		1,568.1	0.2%
	Heavy Oil	1,383.7	0.2%
	Light Oil	162.9	0.0%
	Diesel	14.4	0.0%
	Kerosene	7.1	0.0%
	Jet Oil	0.0	0.0%
Solar		3.5	0.0%
Battery		0.3	0.0%
Total		693,278.7	100.0%

Table 3-50 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, Calendar year 2009

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	39.0%	31.6%	13.6%	25.0%	27.1%
	Average Wind Generation	810.0	638.7	282.0	592.5	577.5
	Average Load	90,361.8	77,109.7	91,520.8	77,362.0	84,148.4
Off-Peak	Capacity Factor	38.6%	31.8%	18.8%	27.6%	29.1%
	Average Wind Generation	797.6	642.3	388.8	657.9	622.0
	Average Load	78,247.0	63,339.0	70,548.1	62,493.6	68,588.6

Table 2-1 Actual PJM footprint summer peak loads: 1999 to 2009

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
1999	Jul 6, 1999	1400	59,365	NA	NA
2000	Jun 26, 2000	1600	56,727	(2,638)	(4.4%)
2001	Aug 9, 2001	1500	54,015	(2,712)	(4.8%)
2002	Aug 14, 2002	1600	63,762	9,747	18.0%
2003	Aug 22, 2003	1600	61,499	(2,263)	(3.5%)
2004	Dec 20, 2004	1900	96,016	34,517	56.1%
2005	Jul 26, 2005	1600	133,761	37,746	39.3%
2006	Aug 2, 2006	1700	144,644	10,883	8.1%
2007	Aug 8, 2007	1600	139,428	(5,216)	(3.6%)
2008	Jun 9, 2008	1700	130,100	(9,328)	(6.7%)
2009	Aug 10, 2009	1700	126,805	(3,295)	(2.5%)

Figure 2-2 Actual PJM footprint summer peak loads: 1999 to 2009

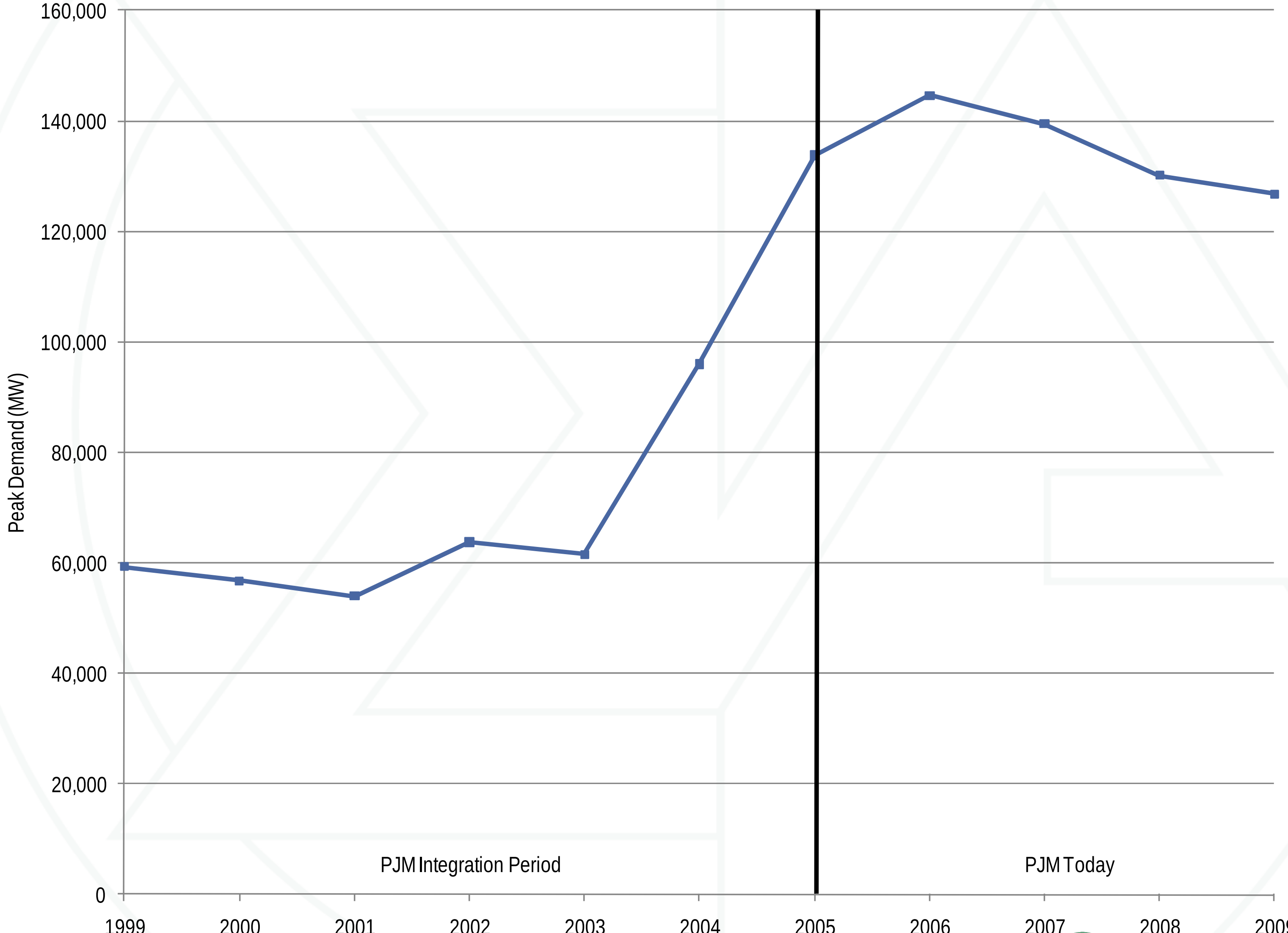

Table 2-33 Type of fuel used (By real-time marginal units): Calendar year 2009

Fuel Type	2009
Coal	74%
Natural Gas	22%
Petroleum	3%
Landfill Gas	1%
Interface	0%
Misc	0%

Table 2-49 PJM real-time average load: Calendar years 1998 to 2009

	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%)

Figure 2-8 PJM real-time average load: Calendar years 2008 to 2009

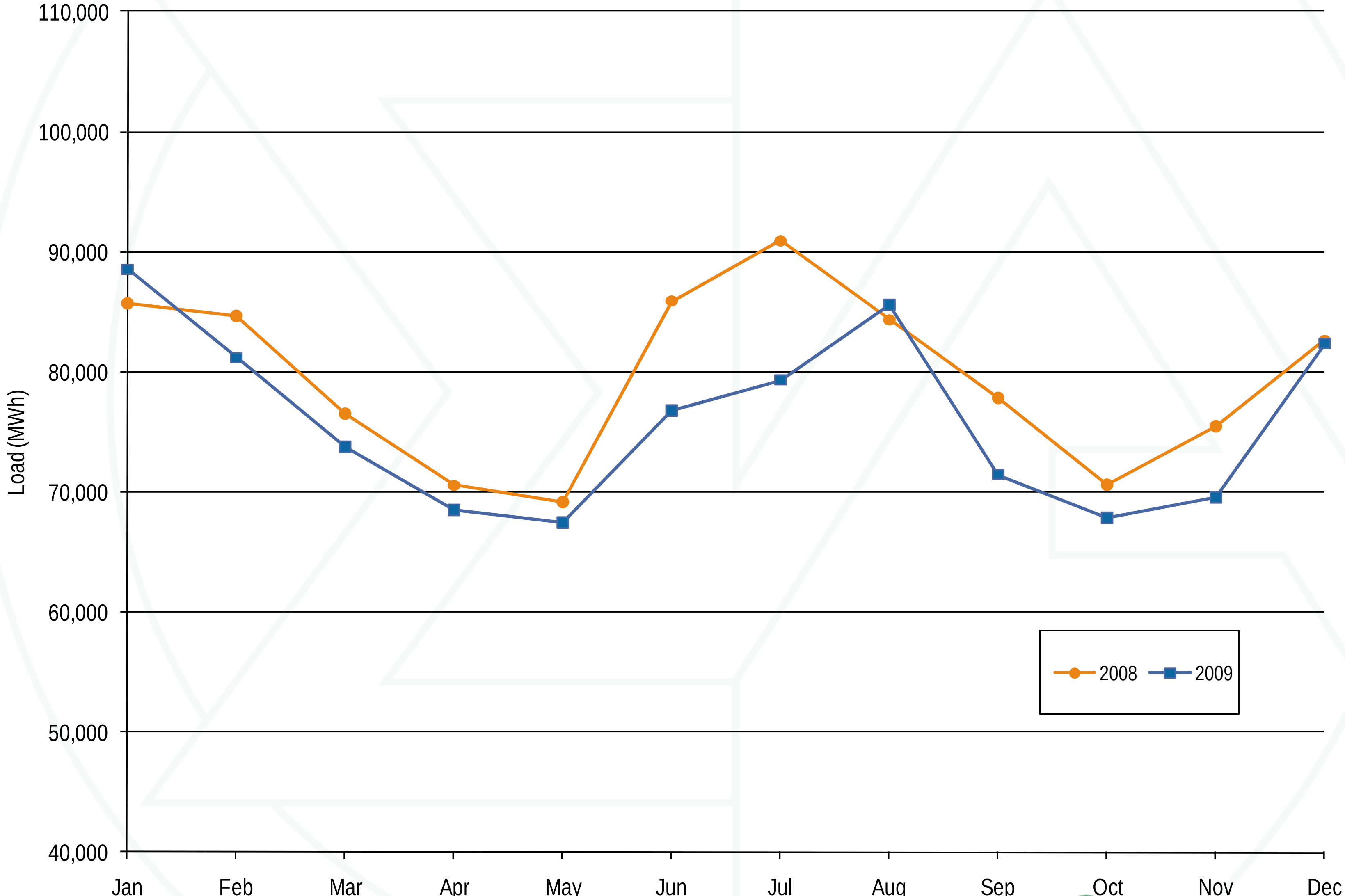

Table 2-59 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2009

	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%)

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 to 2009

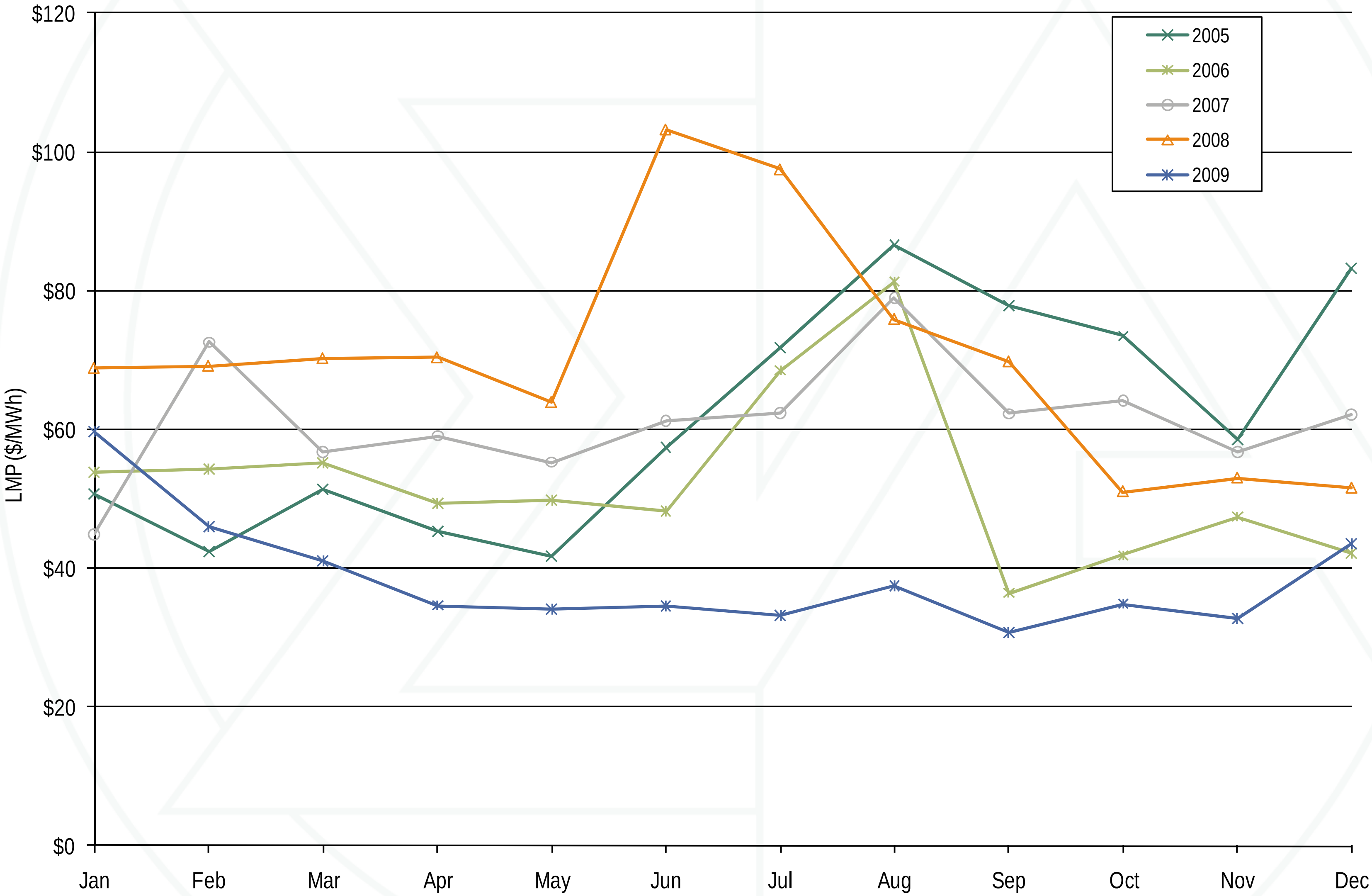

Figure 2-15 Spot average fuel price comparison: Calendar years 2008 to 2009

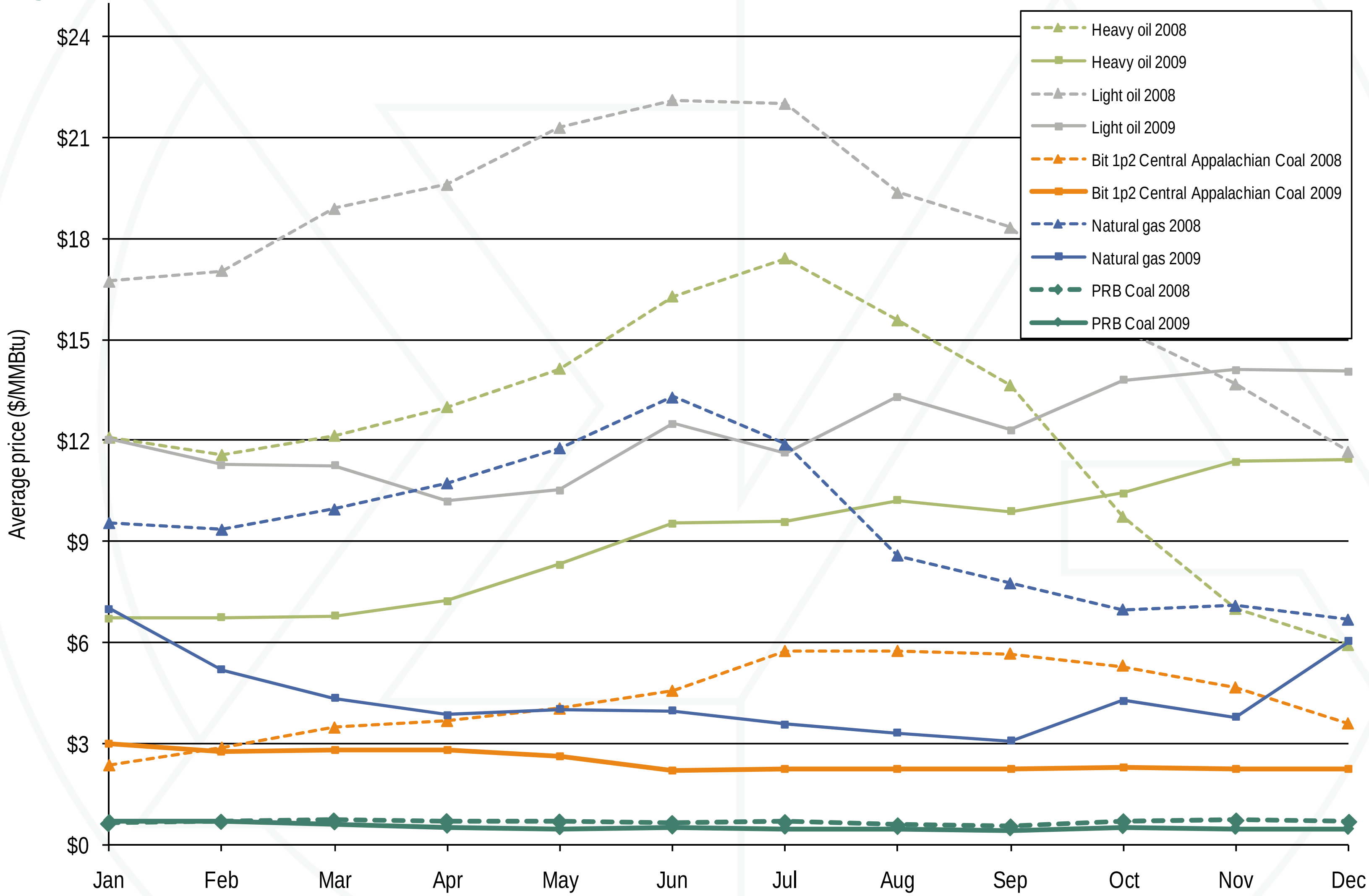

Figure 2-16 Spot average emission price comparison: Calendar years 2008 to 2009

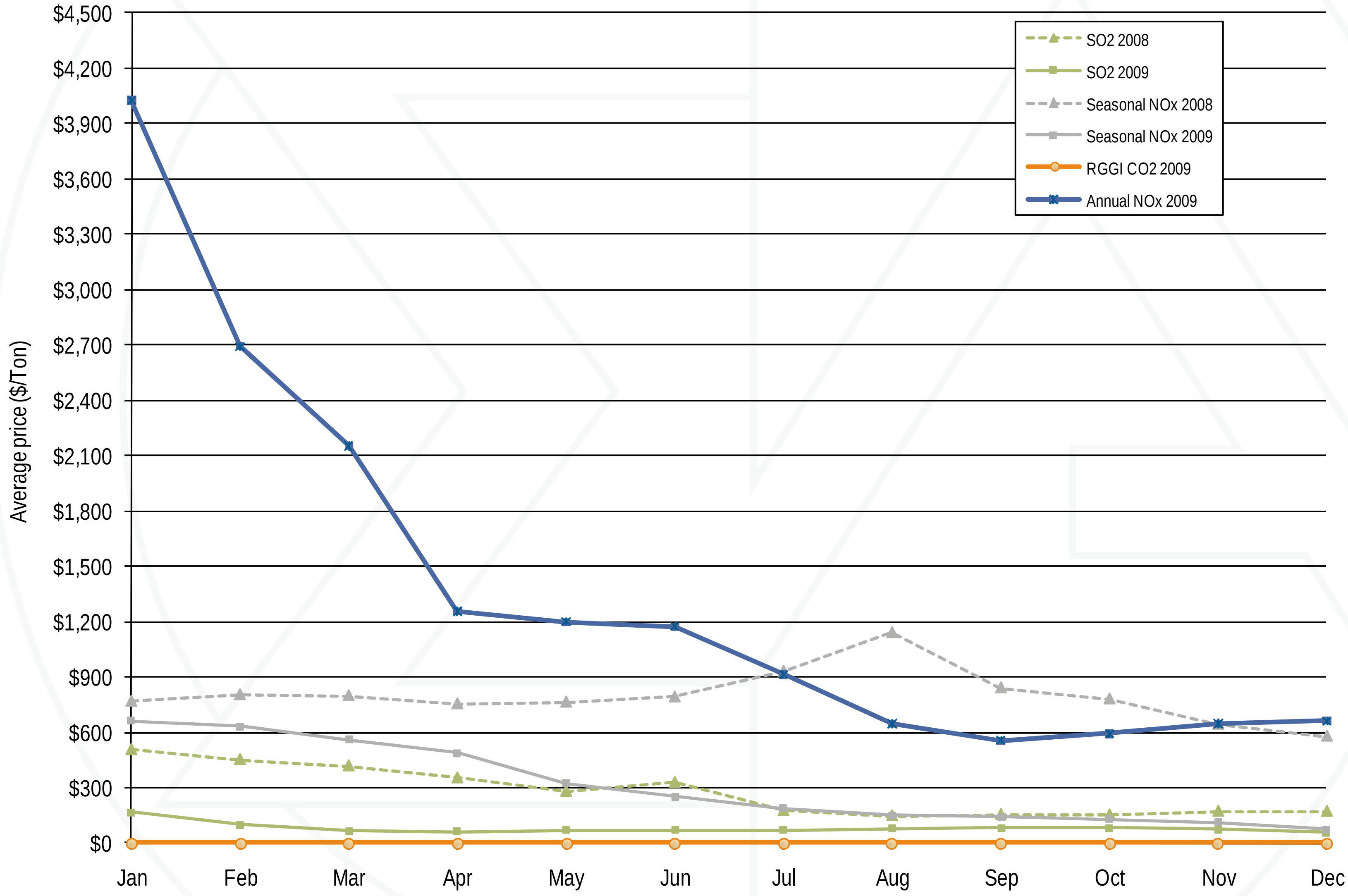

Table 2-63 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2008 Load-Weighted LMP	2009 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$71.13	$63.66	(10.5%)

Table 2-64 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2009

Element	Contribution to LMP	Percent
Coal	$20.53	52.6%
Natural Gas	$12.10	31.0%
10% Cost Adder	$3.73	9.6%
VOM	$2.50	6.4%
Oil	$0.88	2.3%
NO_x	$0.80	2.1%
SO_2	$0.76	1.9%
CO_2	$0.61	1.6%
FMU Adder	$0.17	0.4%
Offline CT Adder	$0.03	0.1%
Municipal Waste	$0.02	0.0%
NA	$0.01	0.0%
Unit LMP Differential	$0.00	0.0%
Shadow Price Limit Adder	($0.01)	(0.0%)
M2M Adder	($0.14)	(0.3%)
Dispatch Differential	($0.15)	(0.4%)
UDS Override Differential	($0.43)	(1.1%)
Markup	($2.38)	(6.1%)
LMP	$39.05	100.0%

Table 2-82 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2009

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	13,986	21,401	423	621	16,879	26,080	487	670
Feb	13,487	22,228	484	739	15,557	24,967	420	624
Mar	13,364	22,639	552	820	15,186	23,243	459	651
Apr	11,363	19,935	380	645	13,900	21,173	428	607
May	12,853	16,863	388	750	13,973	19,274	529	805
Jun	12,375	15,369	315	750	14,777	18,402	482	802
Jul	12,187	17,654	314	821	14,554	19,322	483	808
Aug	12,347	22,931	433	1,020	16,626	23,788	641	1,069
Sep	13,936	22,449	459	993	16,736	23,285	480	957
Oct	13,178	26,649	467	1,246	15,705	26,058	364	1,041
Nov	12,914	22,725	366	903	14,976	22,266	289	726
Dec	11,679	23,958	275	850	14,998	26,715	270	862
Annual	12,873	21,233	405	847	15,322	22,881	444	804

Table 2-84 PJM virtual bids by type of bid parent organization (MW): Calendar year 2009

	Category	Total Virtual Bids MW	Percentage
2009	Financial	106,470,151	31.8%
2009	Physical	228,583,038	68.2%
2009	Total	335,053,190	100%

Table 2-85 PJM virtual bids by top ten aggregates (MW): Calendar year 2009

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,670,457	7,825,323	14,495,780
N ILLINOIS HUB	HUB	3,348,214	1,896,015	5,244,229
AEP-DAYTON HUB	HUB	1,161,223	1,546,752	2,707,976
ComEd	ZONE	214,326	1,240,075	1,454,401
PSEG	ZONE	238,864	1,120,509	1,359,373
MISO	INTERFACE	499,015	594,096	1,093,112
JCPL	ZONE	415,840	564,987	980,828
SOUTHIMP	INTERFACE	843,985	0	843,985
IMO	INTERFACE	805,834	12,185	818,019
NYIS	INTERFACE	184,642	491,293	675,935

Figure 2-19 PJM day-ahead aggregate supply curves: 2009 example day

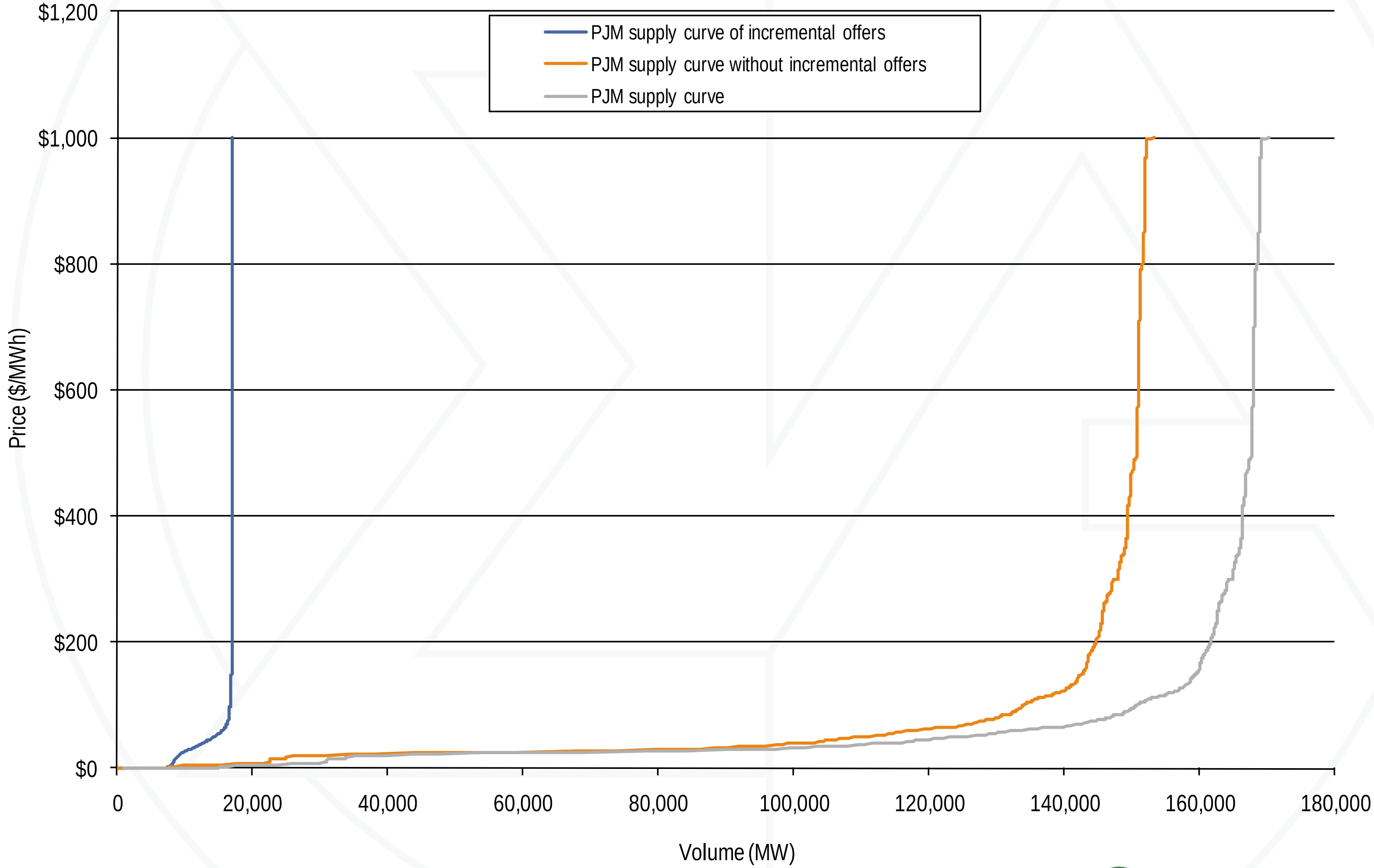

Table 2-87 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
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	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%

Table 2-91 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2008 to 2009

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.3%	17.3%	68.4%	12.6%	15.4%	72.0%	(1.7%)	(1.9%)	3.6%
Feb	15.2%	17.3%	67.5%	13.4%	14.5%	72.1%	(1.7%)	(2.9%)	4.6%
Mar	16.0%	17.1%	66.9%	13.8%	16.7%	69.5%	(2.3%)	(0.4%)	2.6%
Apr	16.6%	18.0%	65.4%	13.5%	17.2%	69.3%	(3.1%)	(0.8%)	3.9%
May	16.0%	18.8%	65.3%	14.6%	18.8%	66.7%	(1.4%)	(0.0%)	1.4%
Jun	13.1%	21.0%	65.9%	12.5%	16.5%	71.0%	(0.6%)	(4.5%)	5.1%
Jul	13.7%	20.6%	65.7%	12.6%	16.9%	70.5%	(1.2%)	(3.7%)	4.8%
Aug	14.9%	22.6%	62.4%	11.7%	16.0%	72.3%	(3.2%)	(6.6%)	9.9%
Sep	14.7%	23.0%	62.2%	12.5%	18.1%	69.4%	(2.3%)	(4.9%)	7.2%
Oct	15.1%	22.7%	62.2%	13.0%	19.8%	67.2%	(2.1%)	(2.9%)	5.0%
Nov	14.8%	22.9%	62.3%	13.2%	19.0%	67.8%	(1.7%)	(4.0%)	5.6%
Dec	12.1%	20.5%	67.4%	11.7%	16.8%	71.5%	(0.4%)	(3.7%)	4.1%
Annual	14.6%	20.1%	65.2%	12.9%	17.0%	70.1%	(1.8%)	(3.1%)	4.9%

Table 2-4 Annual offer-capping statistics: Calendar years 2005 to 2009

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2005	1.8%	0.4%	0.2%	0.1%
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%

Table 2-6 Three pivotal supplier results summary for regional constraints: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	714	691	97%	49	7%
	Off Peak	216	206	95%	26	12%
AP South	Peak	1,777	1,012	57%	1,134	64%
	Off Peak	951	518	54%	642	68%
Kammer	Peak	3,786	3,508	93%	624	16%
	Off Peak	4,145	3,619	87%	1,064	26%

Table 2-8 Three pivotal supplier results summary for the Central, East and West Interfaces: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	23	23	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA
West	Peak	332	321	97%	30	9%
	Off Peak	65	65	100%	0	0%

Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Absecon - Lewis	Peak	61	0	0%	61	100%
	Off Peak	16	0	0%	16	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Absecon - Lewis	Peak	8	19	1	0	1
	Off Peak	7	27	1	0	1

Table 3-21 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005	2006	2007	2008	2009
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009

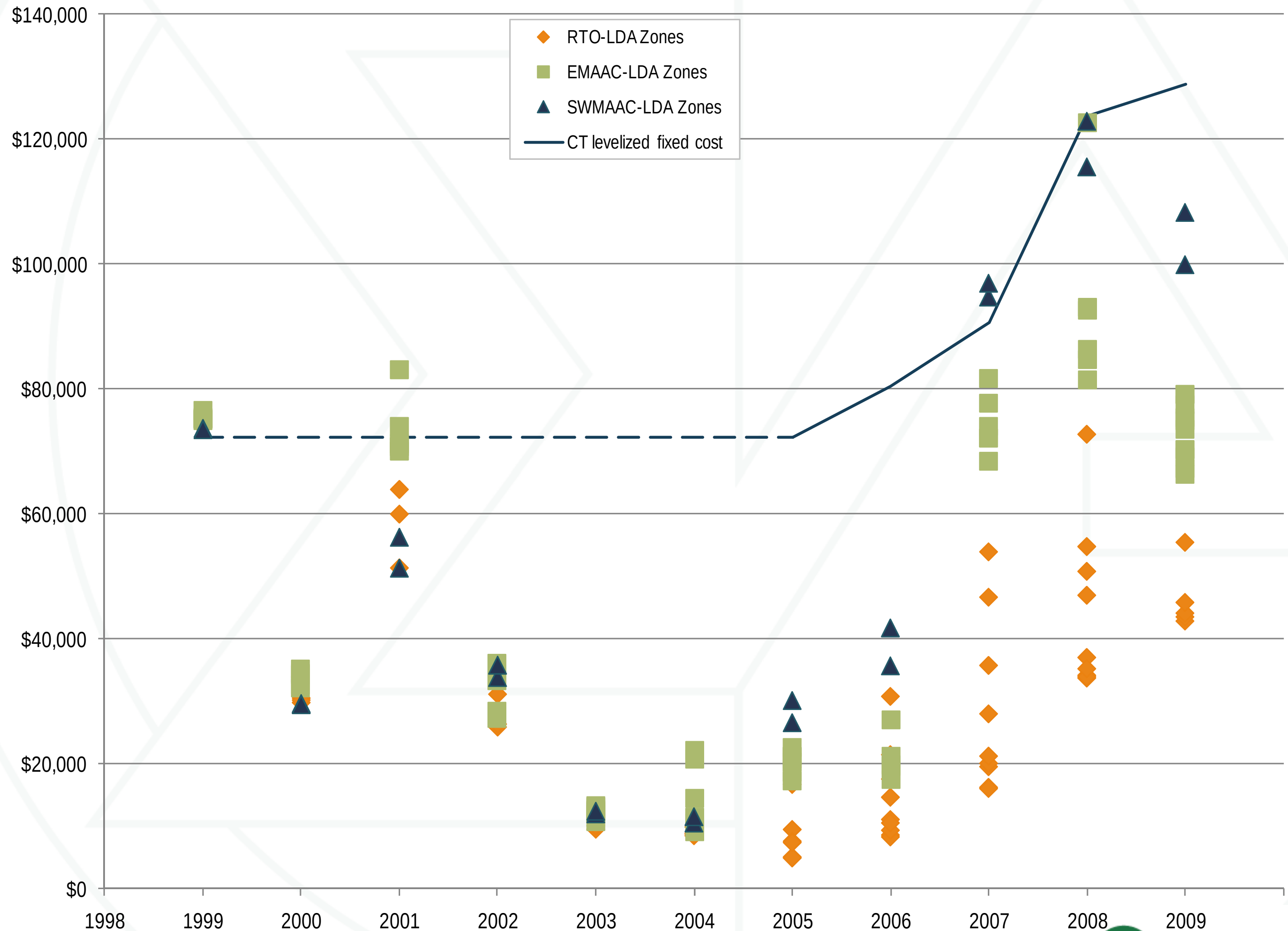

Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009

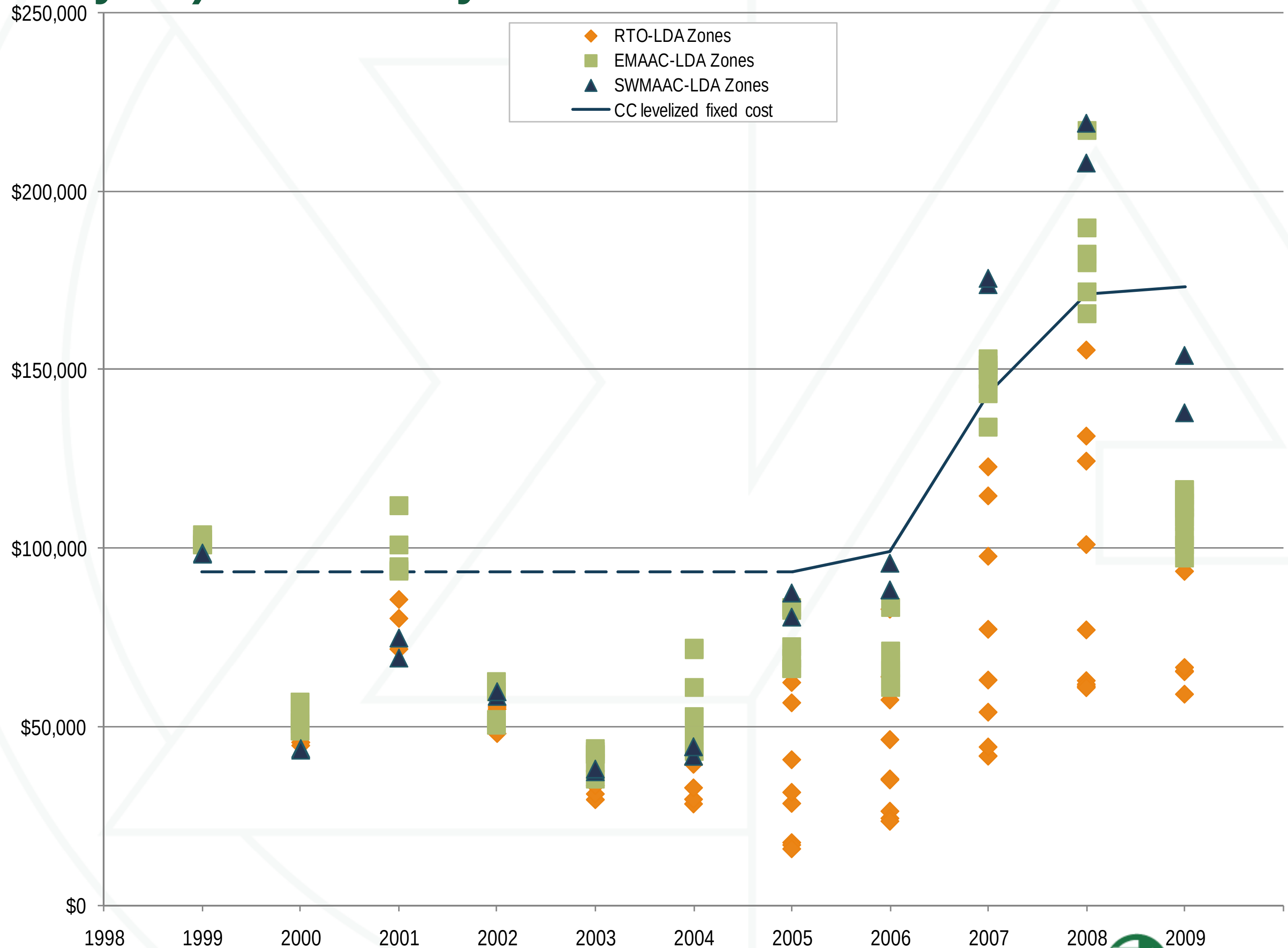

Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009

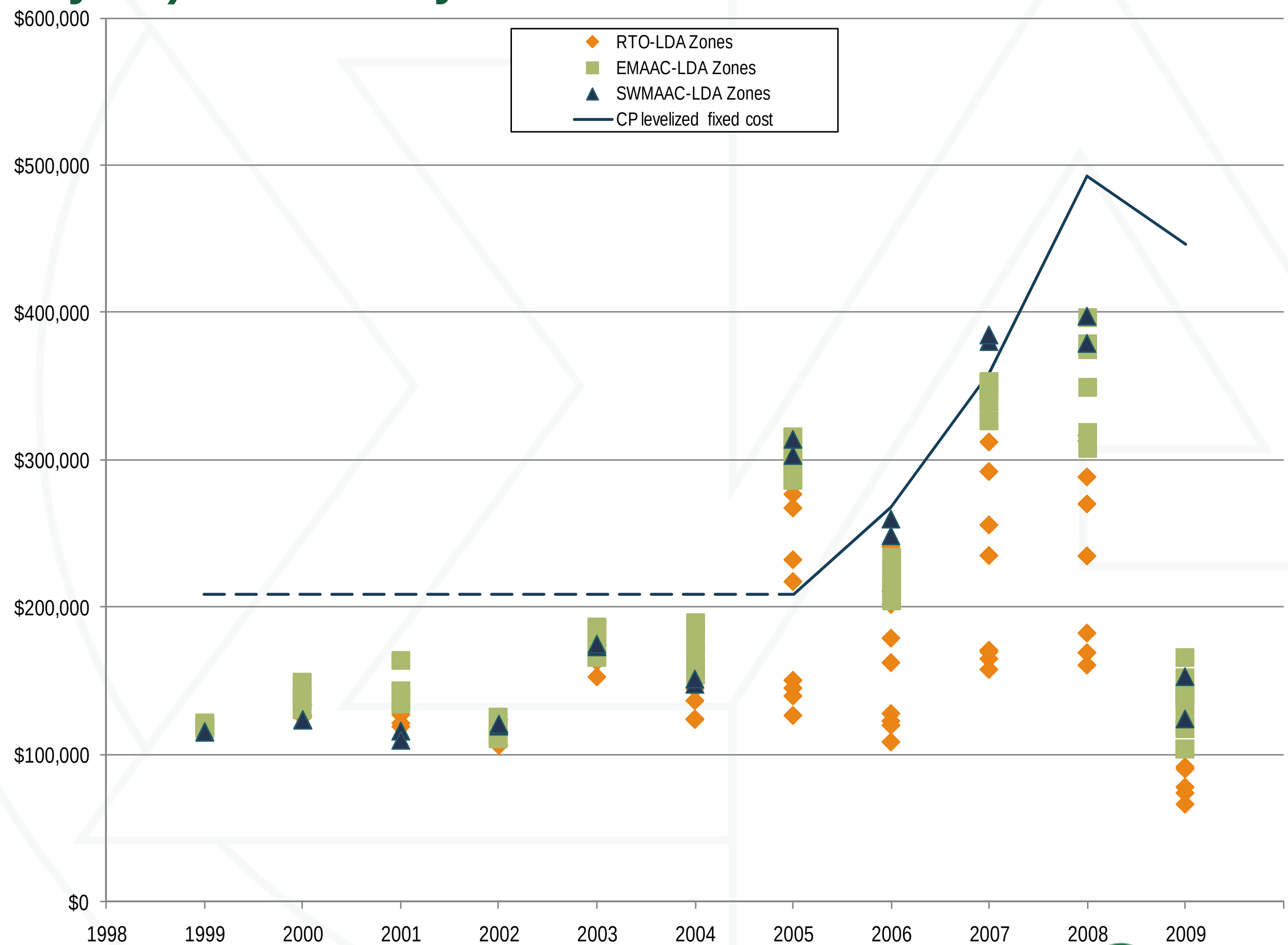

Table 3-33 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2007 through 2009

	2007		2008		2009	
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	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - Two on One Frame F Technology	74%	90%	74%	100%	63%	93%
CT - Third Generation Aero (GE LM 6000)	45%	79%	41%	100%	28%	100%
CT - Third Generation Frame F	47%	100%	48%	100%	20%	100%
Nuclear	100%	100%	100%	100%	93%	100%
Sub-Critical Coal	93%	95%	85%	95%	25%	75%
Super Critical Coal	98%	100%	100%	100%	23%	86%

Table 2-93 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	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	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Figure 2-23 Demand Response revenue by market: Calendar years 2002 through 2009

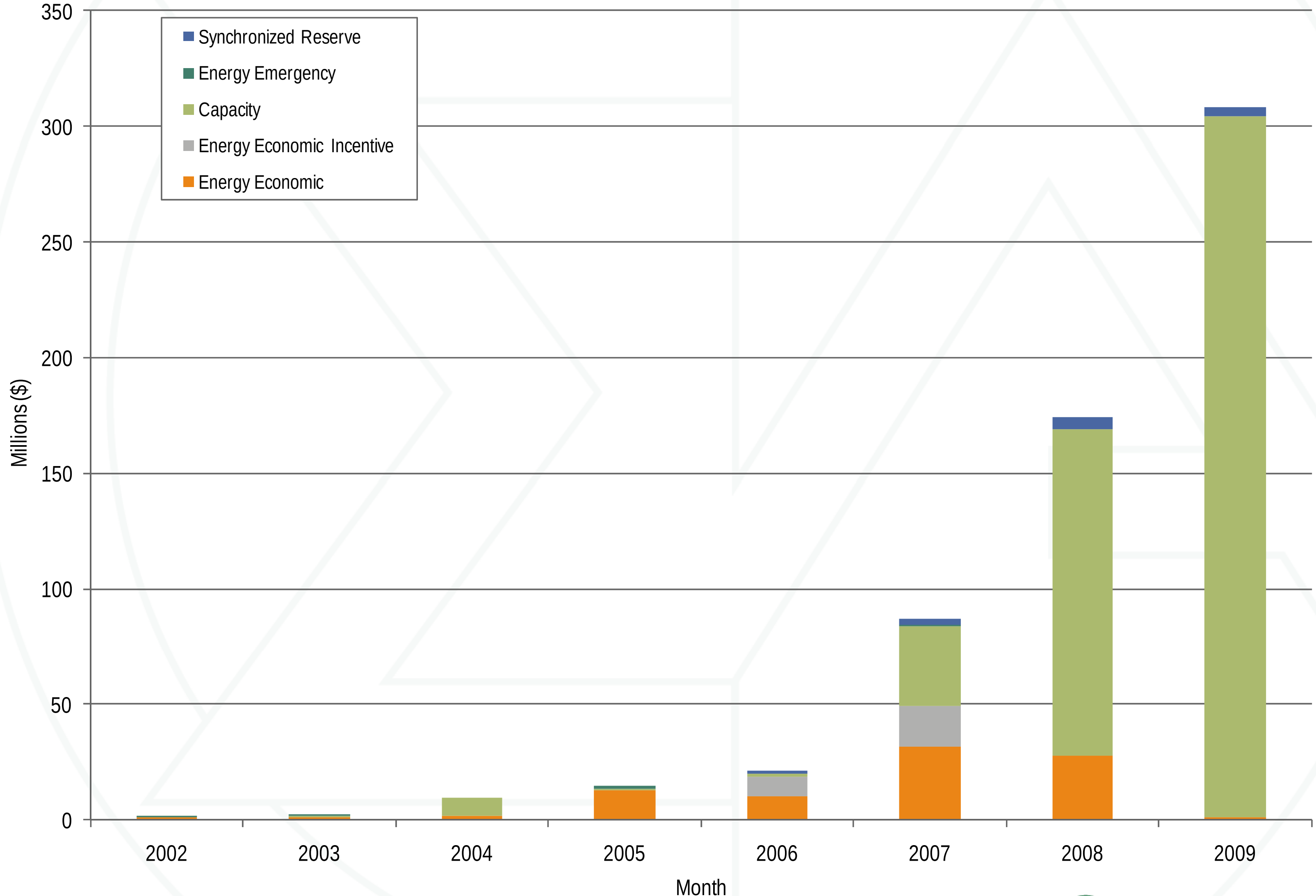

Figure 2-24 Economic Program payments: Calendar years 2007 (without incentive payments), 2008 and 2009

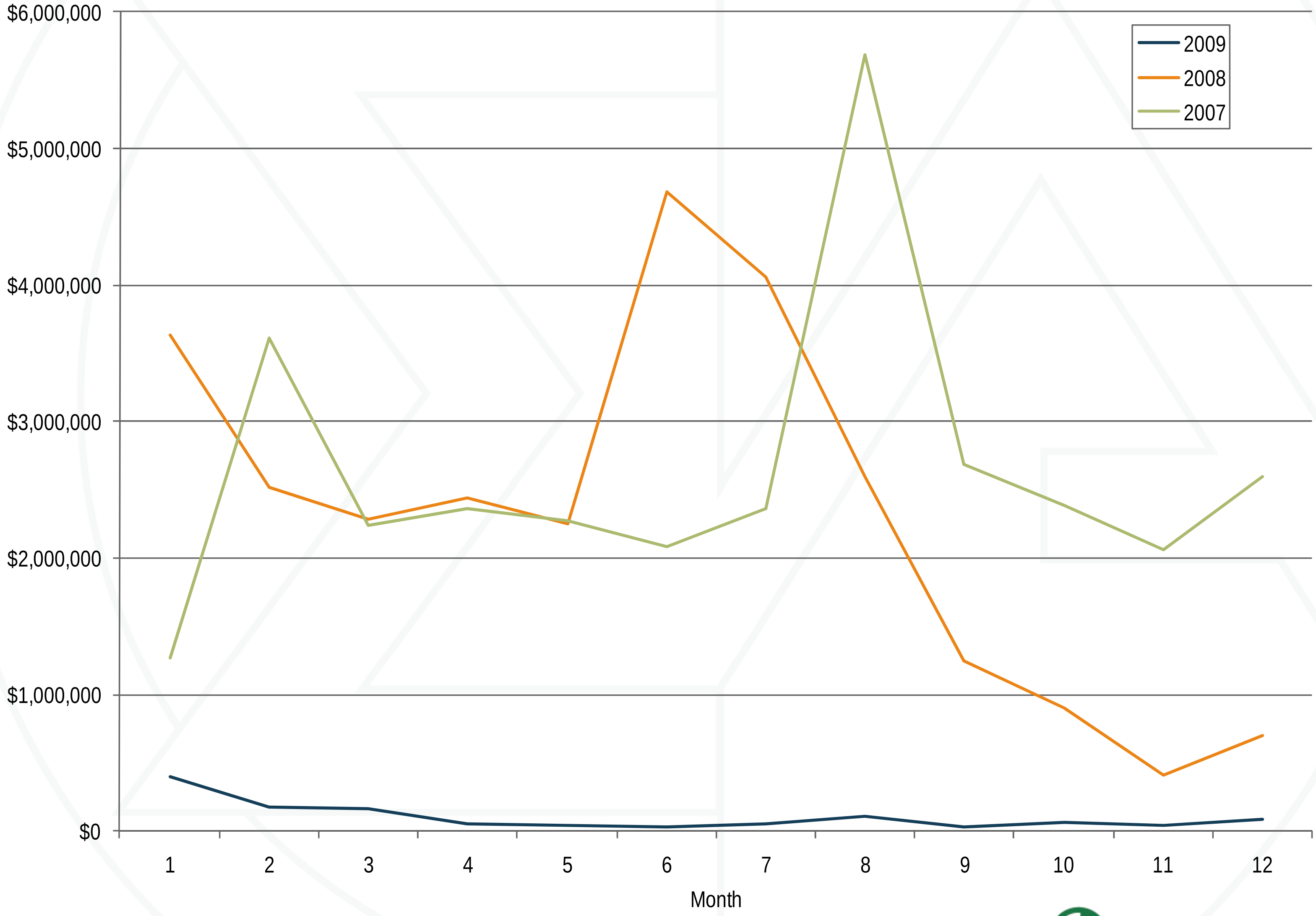

Table 2-107 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2012/2013

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	518.5
2009/2010	906.9	865.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.3

Table 3-51 Operating reserve credits and charges

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

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

Table 3-52 Operating reserve deviations

Deviations		
Day ahead		Real time
Day-ahead decrement bids Day-ahead load Day-ahead sales Day-ahead export transactions	Demand (Withdrawal) (RTO, East, West)	Real-time load Real-time sales Real-time export transactions
Day-ahead increment offers Day-ahead purchases Day-ahead import transactions	Supply (Injection) (RTO, East, West)	Real-time purchases Real-time import transactions
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Table 3-53 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	1.) **Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	1.) **Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV 2.) **Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 3-54 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2009

	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%)

Figure 3-15 Operating reserve credits: Calendar year 2009

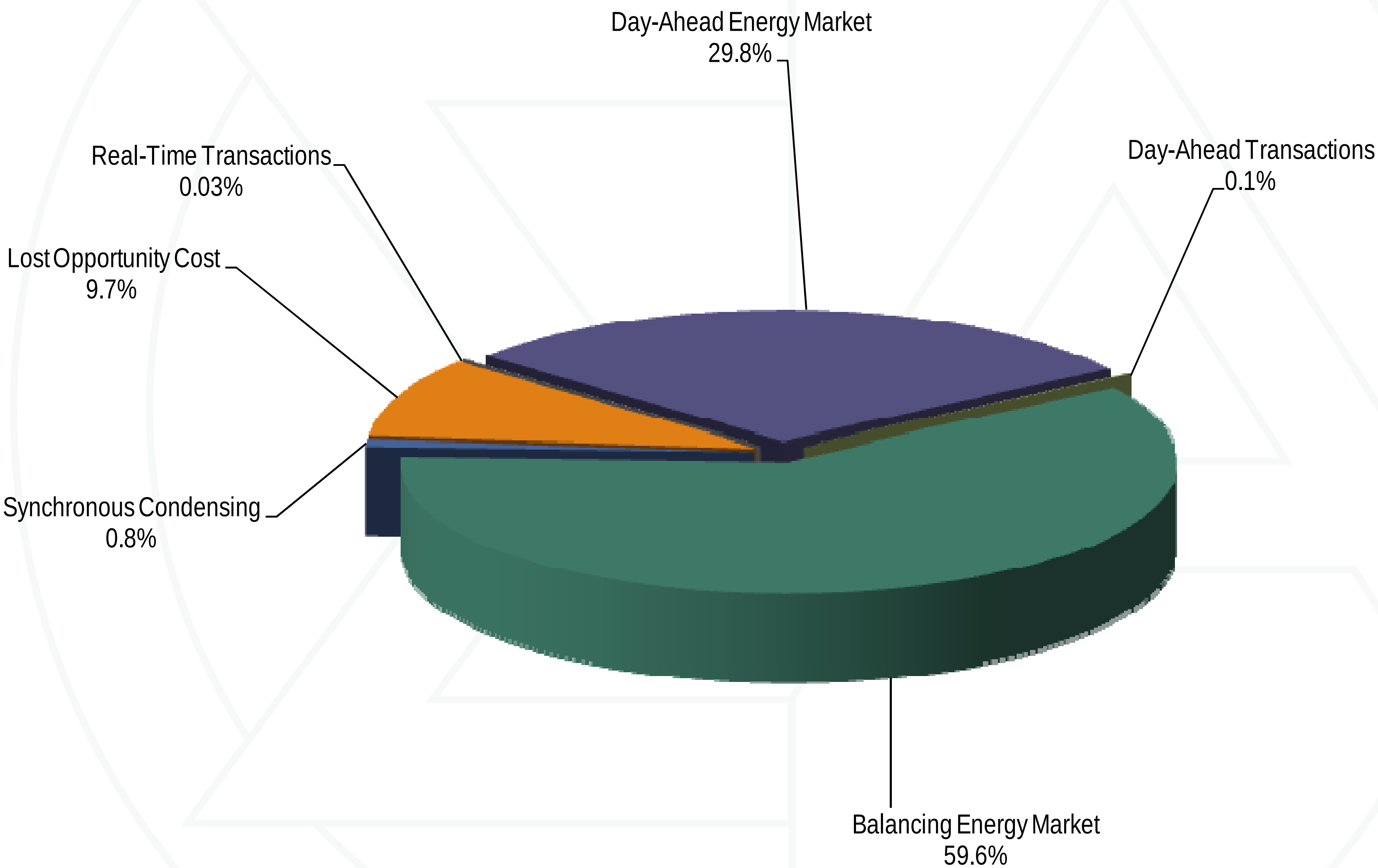

Table 3- 62 Credits by operating reserve market (By unit type): Calendar year 2009

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	44.6%	0.0%	31.5%	2.9%
Combustion Turbine	1.2%	100.0%	34.5%	35.6%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.1%	1.2%
Landfill	0.0%	0.0%	0.0%	43.1%
Nuclear	0.0%	0.0%	0.0%	0.5%
Steam	54.1%	0.0%	33.7%	16.6%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$94,707,723	$2,495,097	$189,739,803	$30,883,718

Table 3-74 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2009

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$9,672,322	$10,738,258	($1,065,936)
Feb	$4,034,001	$5,681,839	($1,647,837)
Mar	$6,745,711	$8,589,442	($1,843,731)
Apr	$2,331,339	$2,736,472	($405,133)
May	$3,602,363	$4,020,105	($417,741)
Jun	$4,827,989	$5,606,584	($778,595)
Jul	$4,792,394	$5,383,784	($591,390)
Aug	$7,234,696	$7,720,394	($485,698)
Sep	$3,973,924	$4,772,689	($798,765)
Oct	$4,664,169	$5,536,136	($871,967)
Nov	$3,380,119	$3,836,906	($456,787)
Dec	$5,536,595	$6,614,578	($1,077,983)
Total	$60,795,622	$71,237,186	($10,441,564)

Table 3-76 Impact of segmented make whole payments: December 2008 through December 2009

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
Total		$199,302,047	$207,476,453	$8,174,406

Table 3-83 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2009

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$40,271,049	12.7%	12.7%	$104,362,793	32.8%	32.8%
2	$26,582,418	8.4%	21.0%	$53,684,600	16.9%	49.7%
3	$13,129,115	4.1%	25.2%	$30,268,335	9.5%	59.3%
4	$8,972,470	2.8%	28.0%	$18,858,384	5.9%	65.2%
5	$7,153,457	2.3%	30.2%	$15,000,057	4.7%	69.9%
6	$6,136,280	1.9%	32.2%	$14,238,849	4.5%	74.4%
7	$4,227,166	1.3%	33.5%	$13,784,436	4.3%	78.7%
8	$4,178,410	1.3%	34.8%	$7,705,847	2.4%	81.1%
9	$3,618,783	1.1%	36.0%	$7,539,983	2.4%	83.5%
10	$3,507,989	1.1%	37.1%	$6,033,195	1.9%	85.4%

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2009

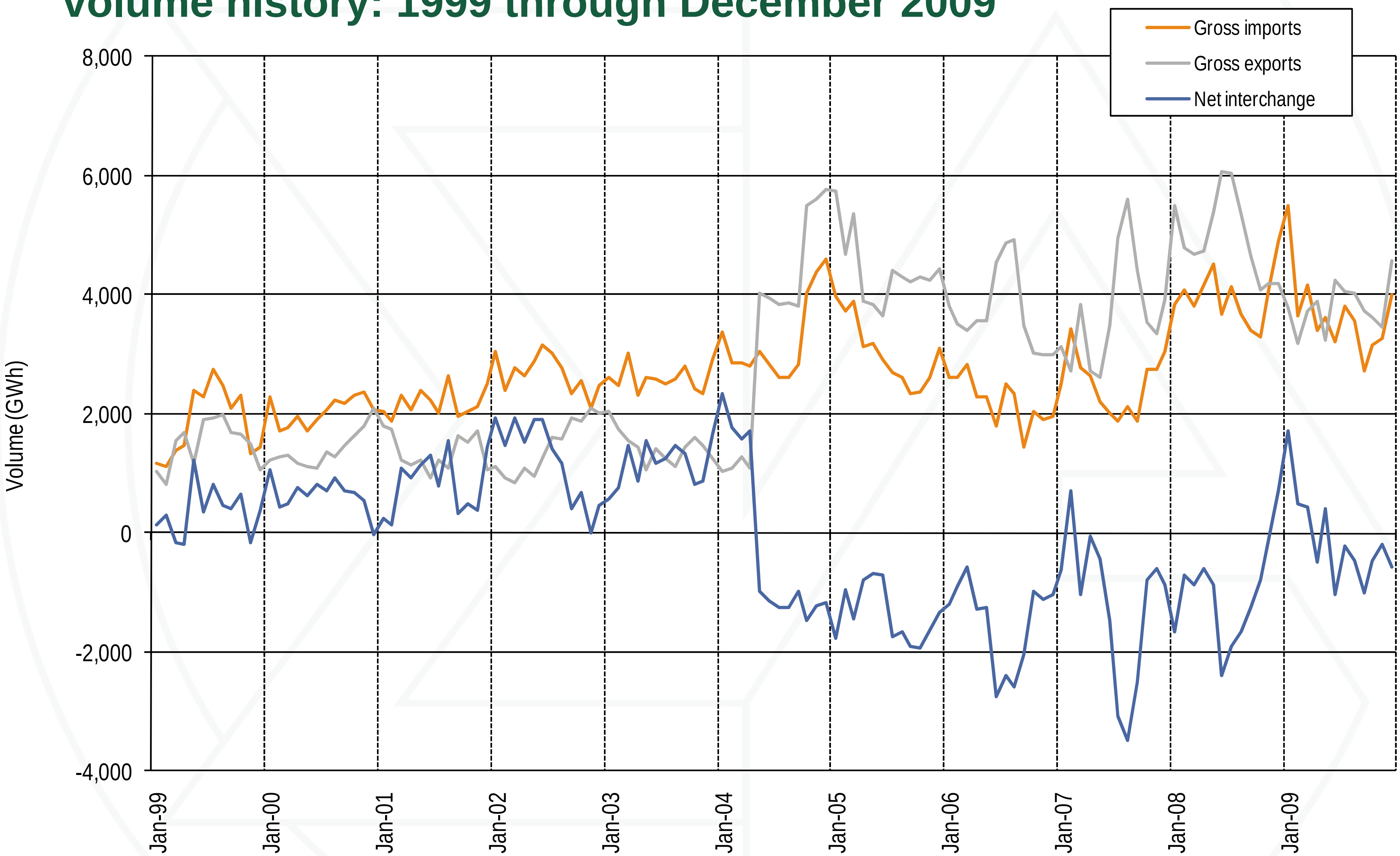

Figure 4-4 PJM's footprint and its external interfaces

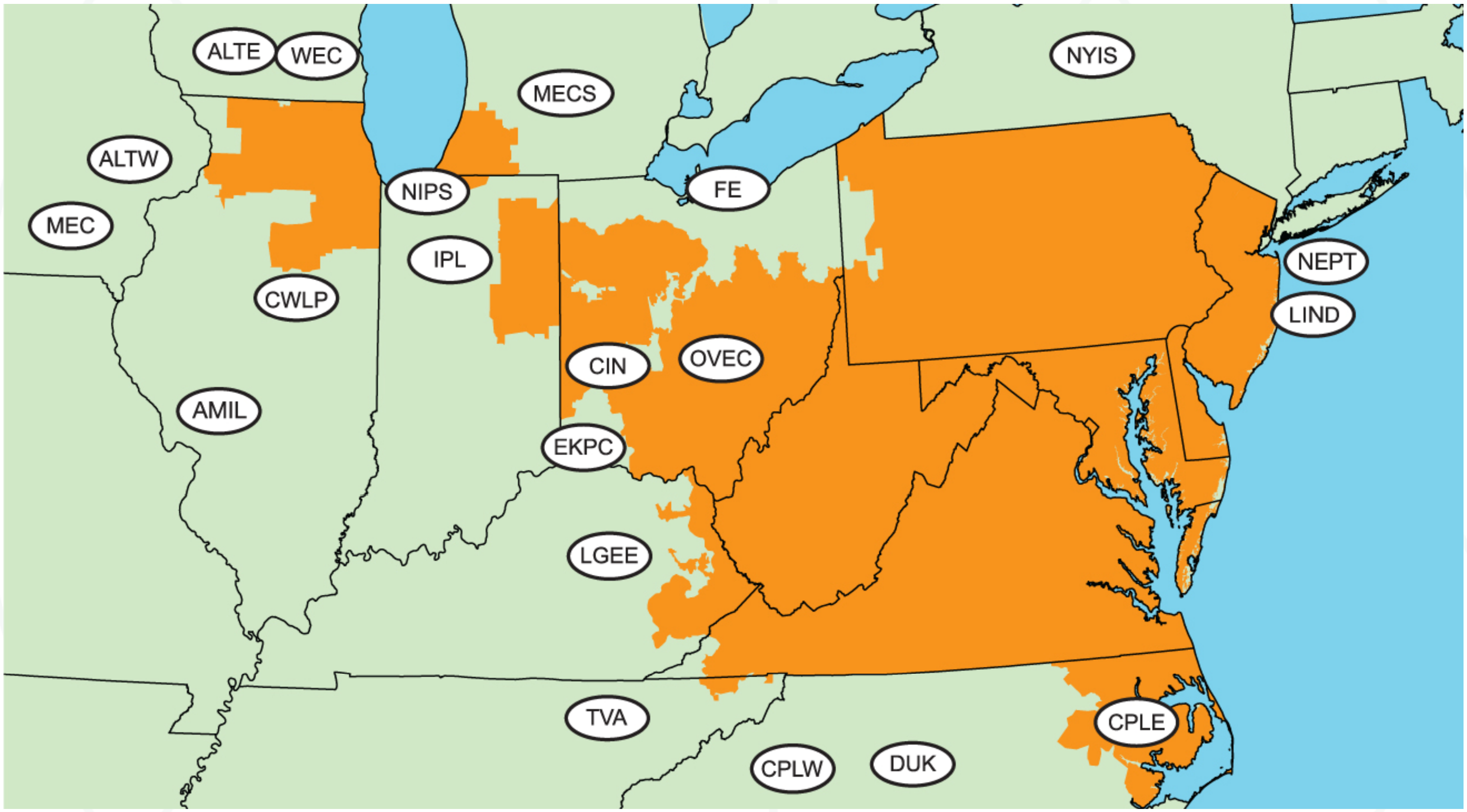

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2009

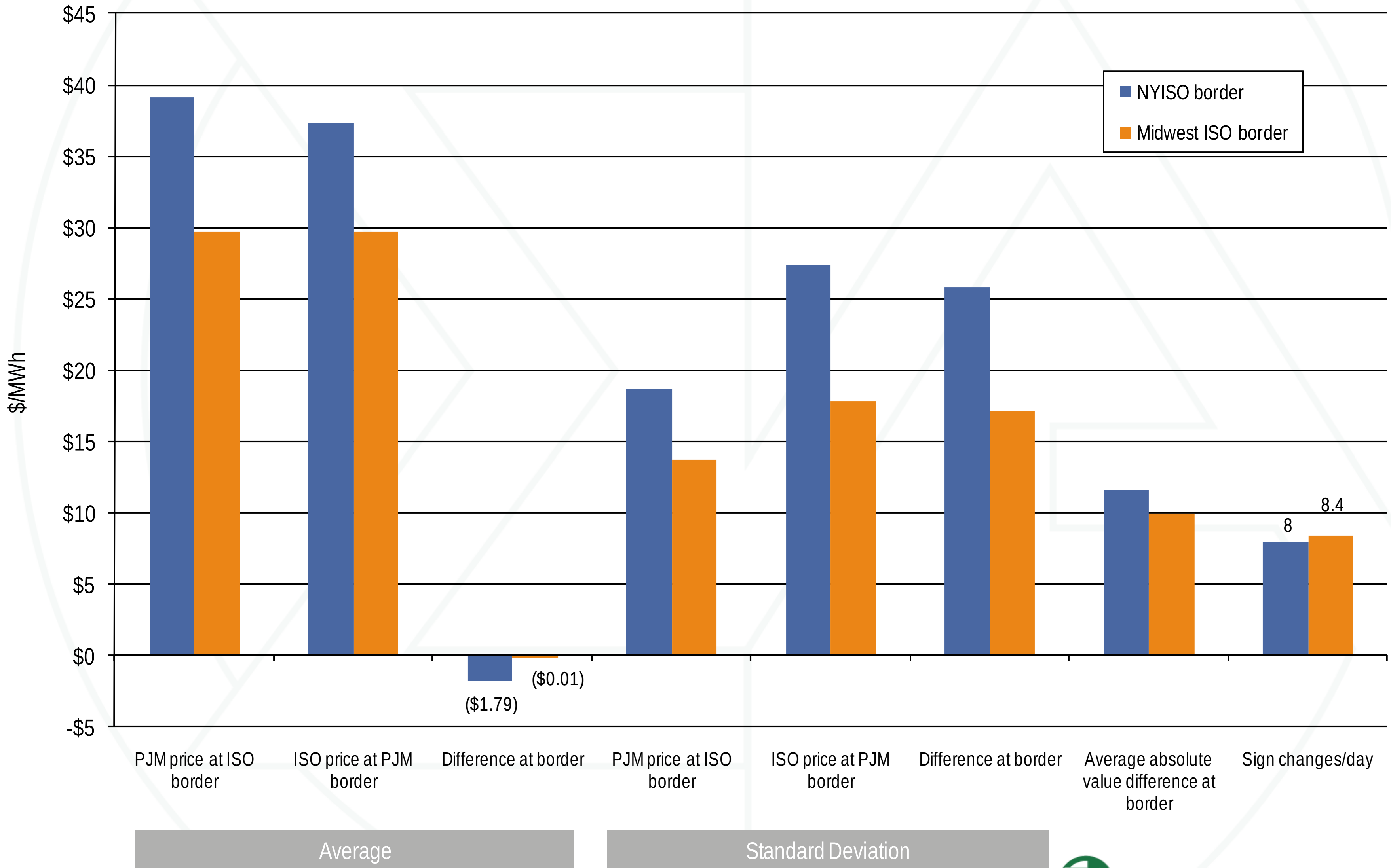

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through December 2009

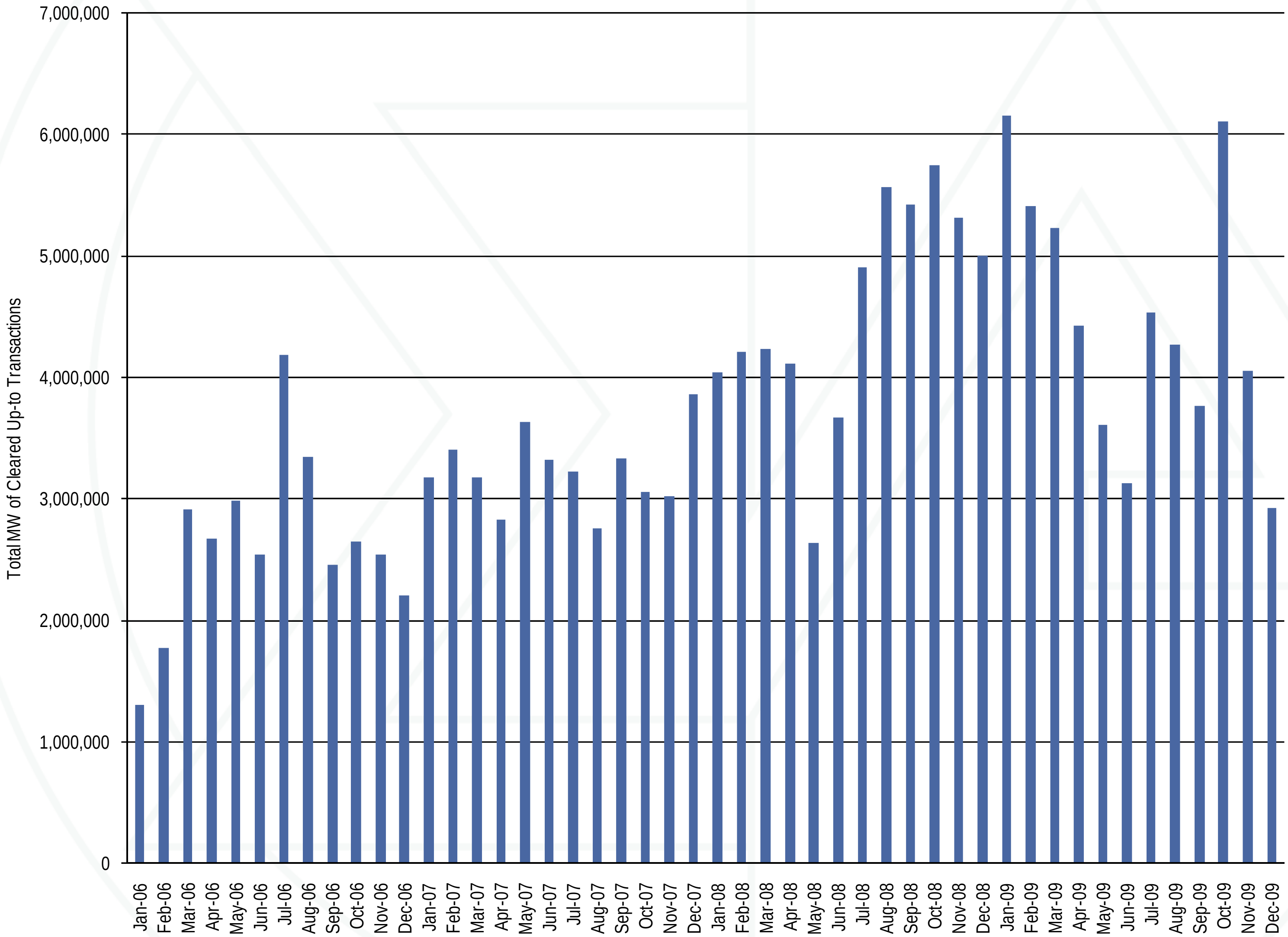

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: Calendar year 2009

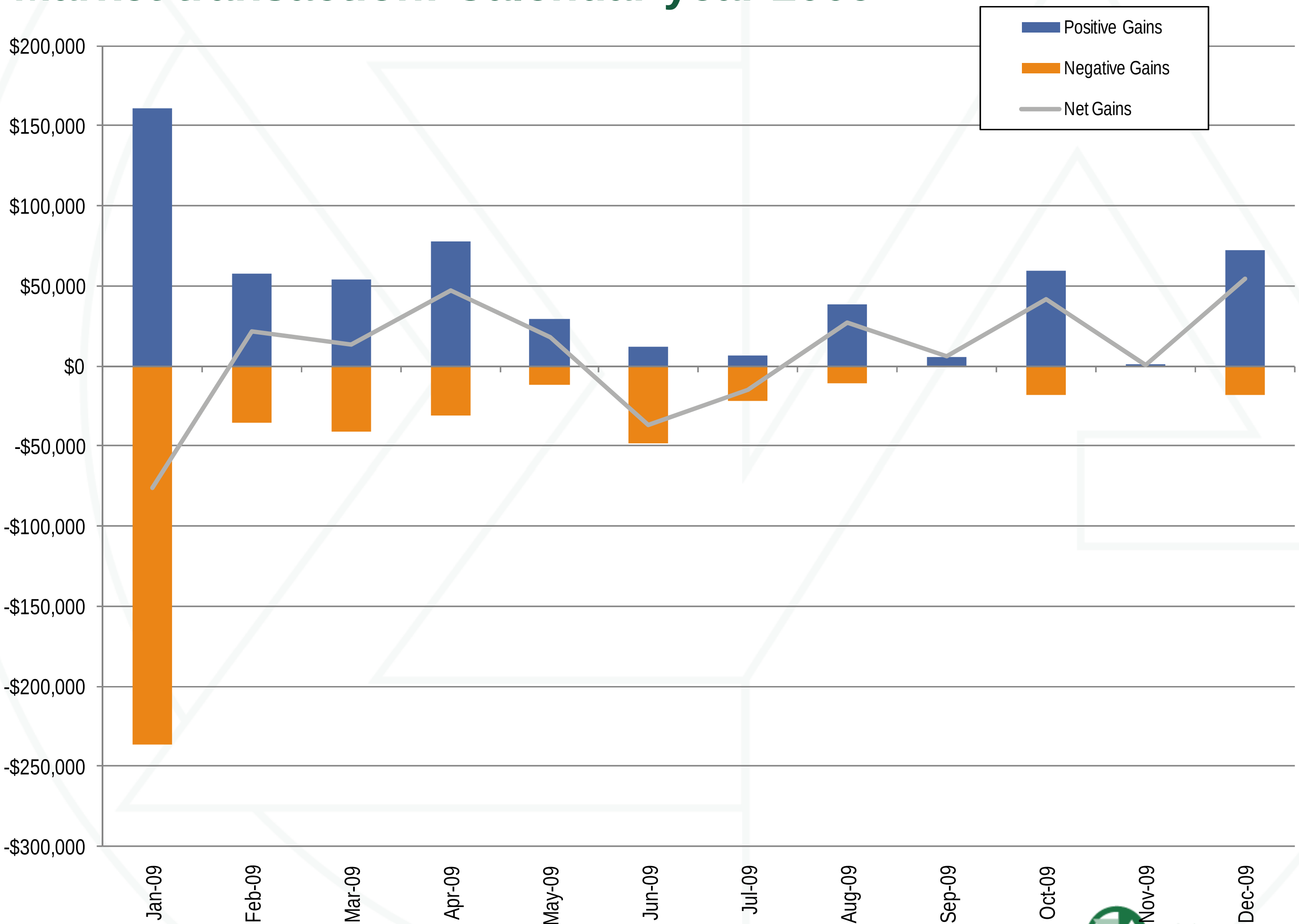

Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: Calendar year 2009

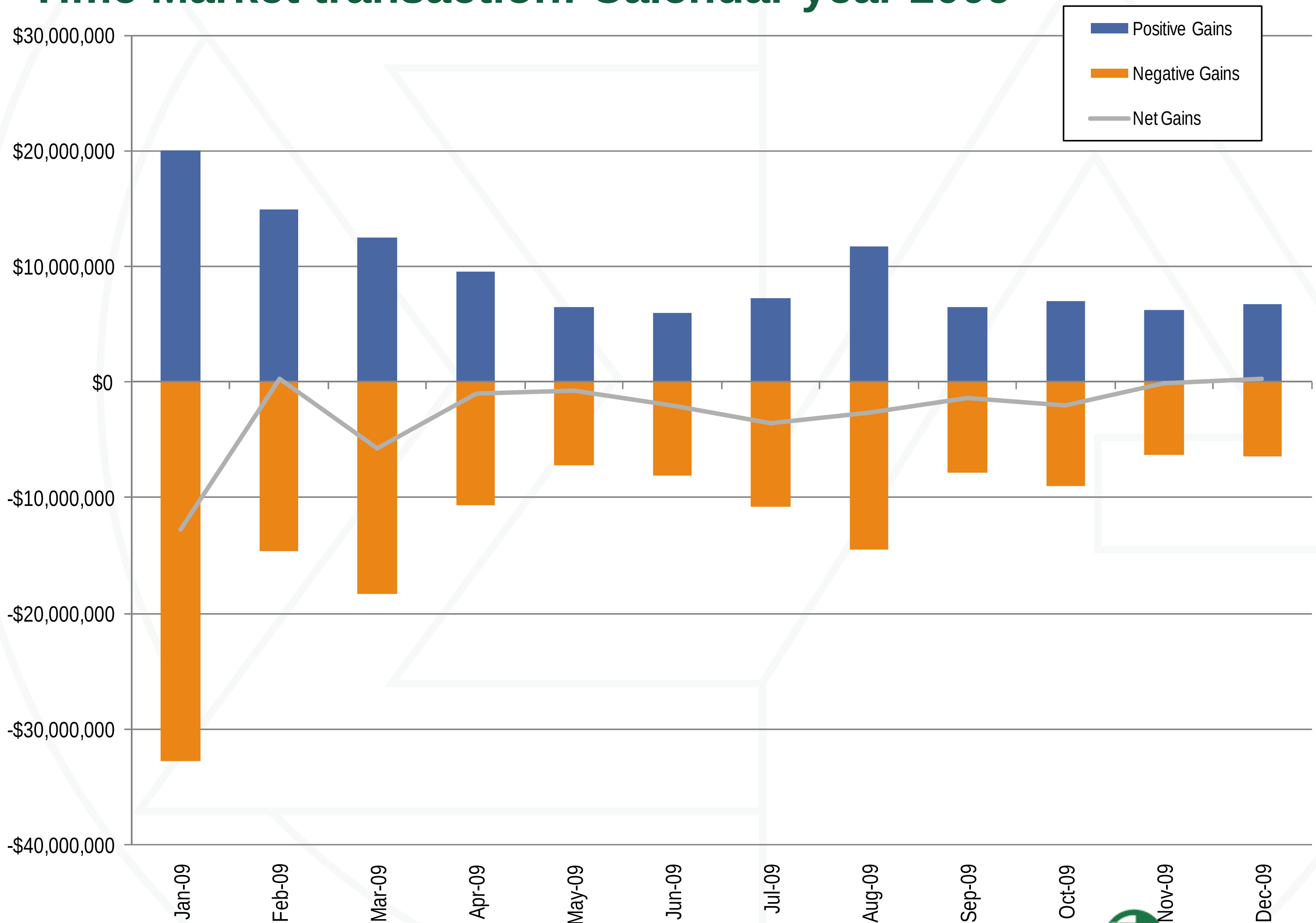

Figure 4-30 Spot import service utilization: Calendar year 2009

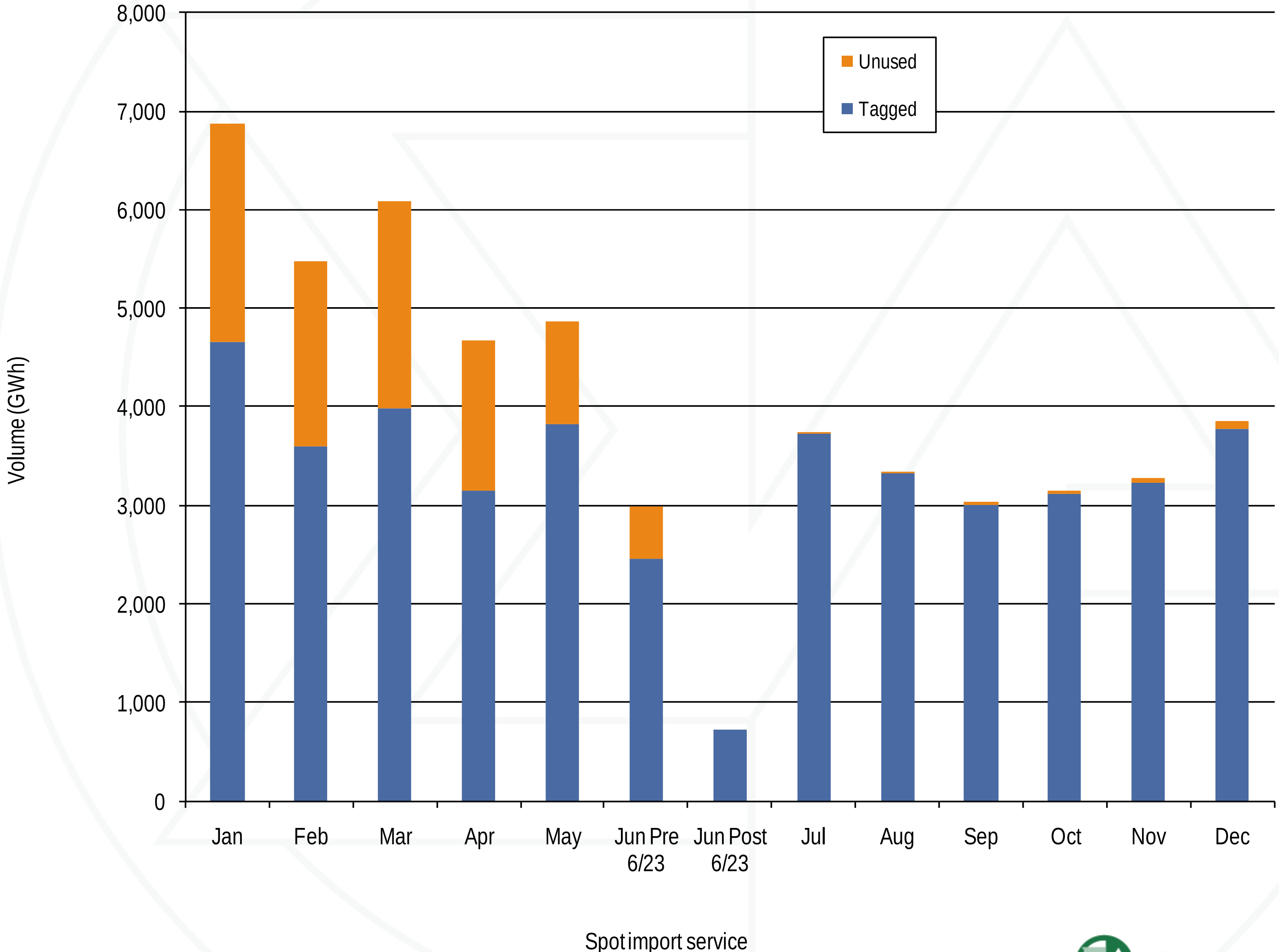

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through December 2009

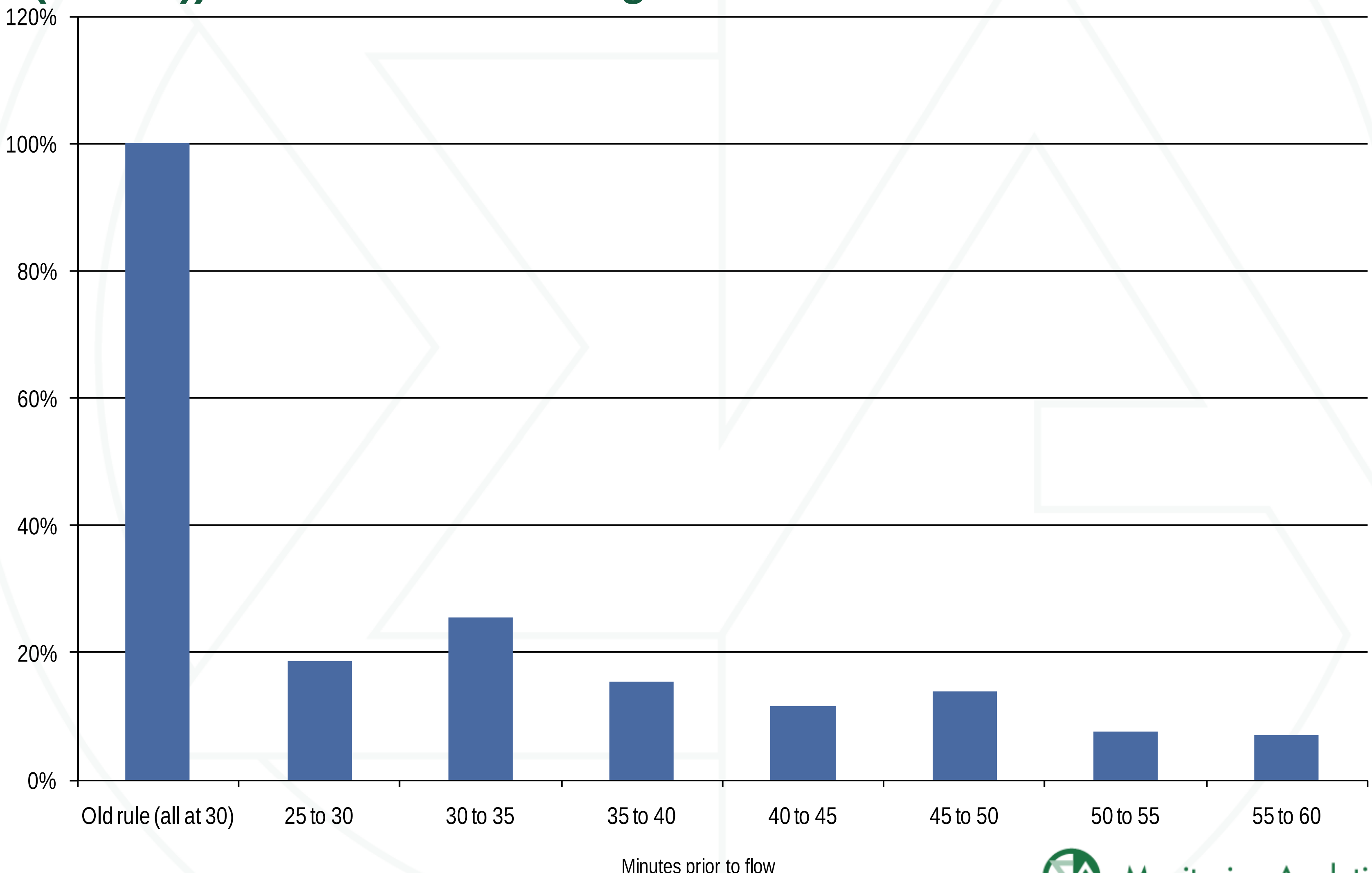

Table 5-5 PJM capacity summary (MW): June 1, 2008, through May 31, 2012

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,240.5	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared						568.9
ILR	1,636.3	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target						3,343.3

Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$178.27	
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012

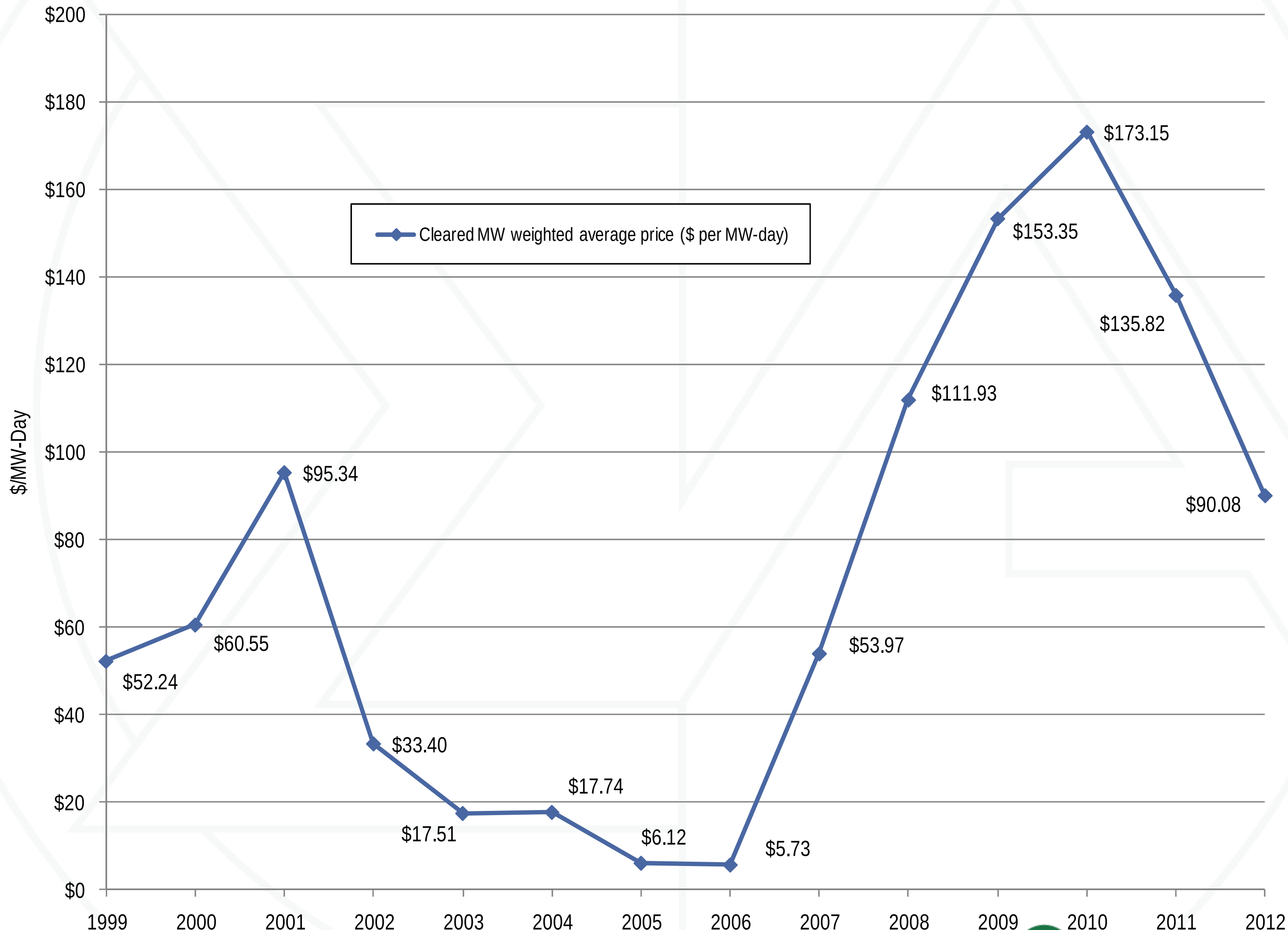

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009

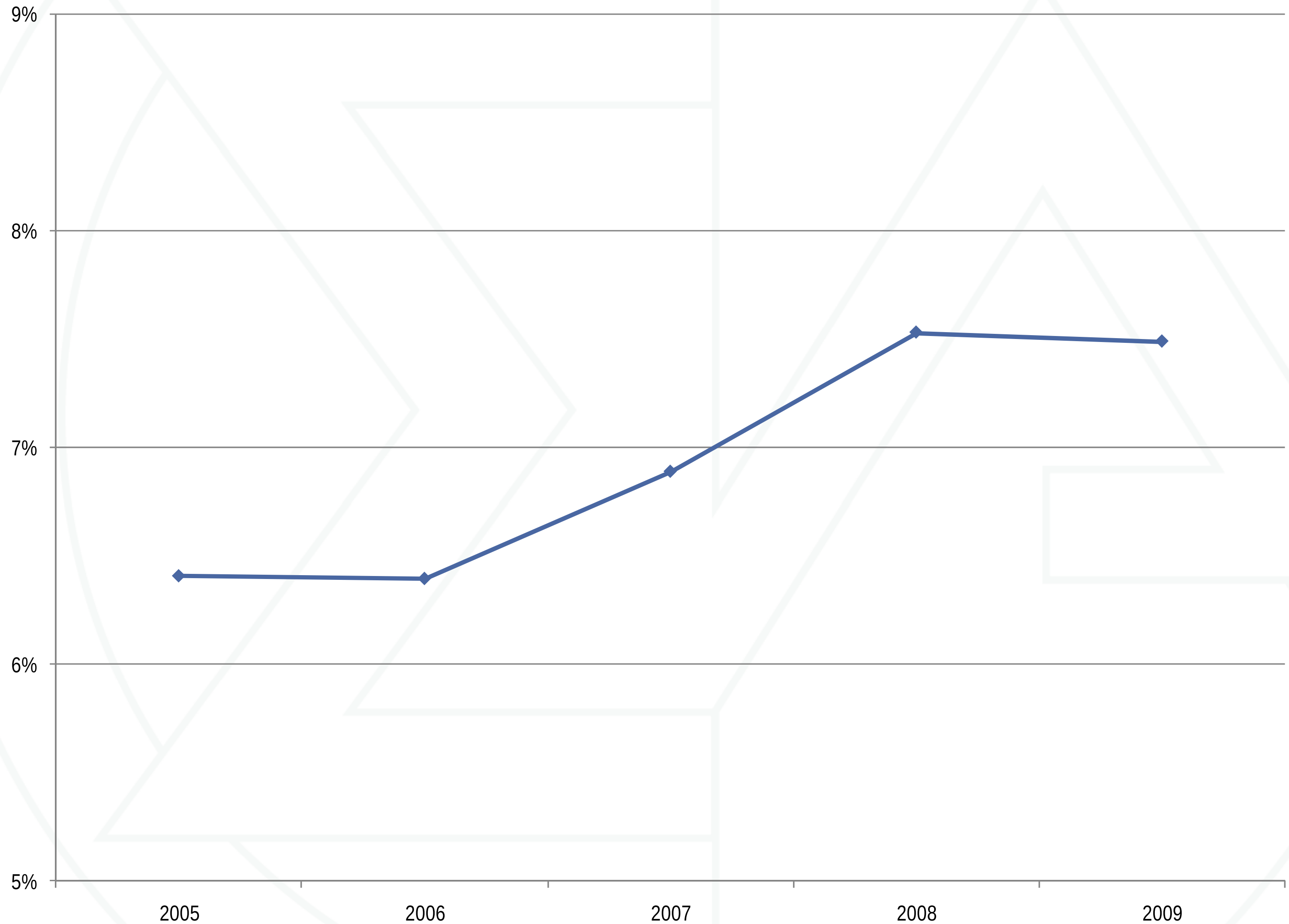

Figure 5-9 PJM 2009 Distribution of EFORd data by unit type

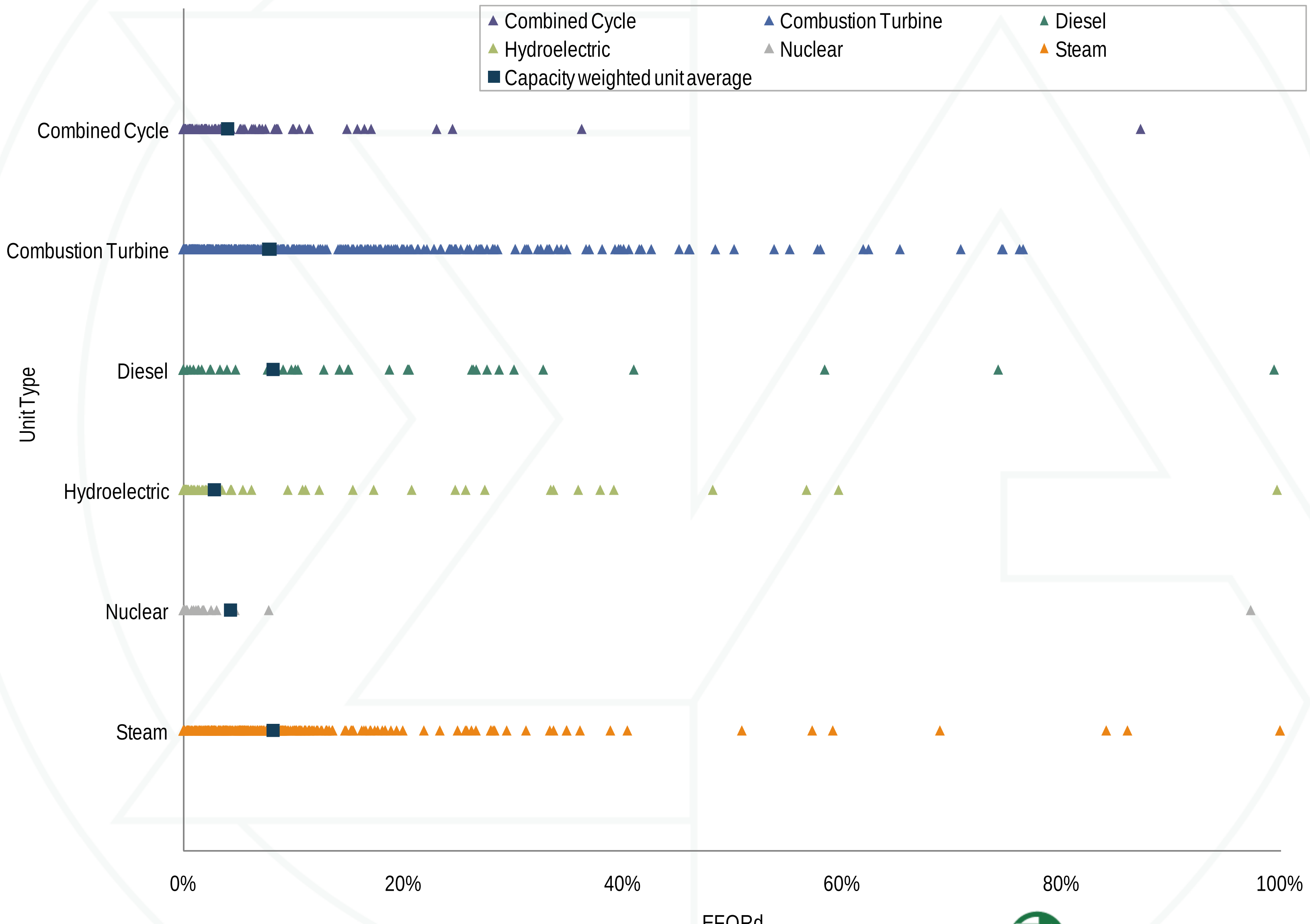

Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2009

	EFORd	XEFORd	EFORp
Combined Cycle	3.8%	3.6%	2.9%
Combustion Turbine	9.8%	8.3%	2.5%
Diesel	10.2%	8.0%	5.3%
Hydroelectric	3.2%	3.0%	2.9%
Nuclear	4.1%	4.1%	4.3%
Steam	9.3%	8.0%	4.7%
Total	7.5%	6.6%	4.0%

Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2009

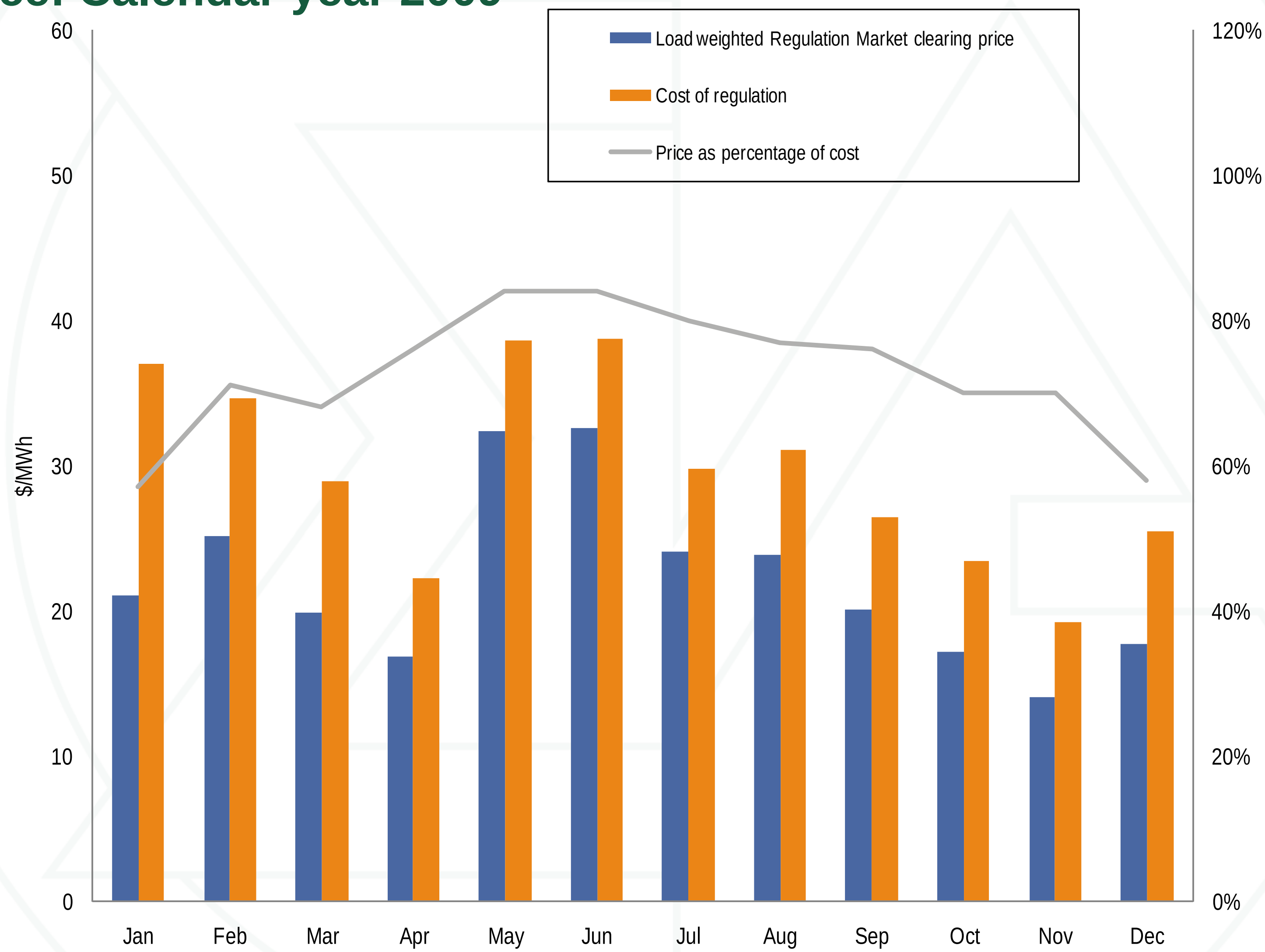

Table 6-8 Summary of changes to Regulation Market design

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 6-9 Regulation Market pivotal supplier test results: December 2008 through December 2009 and December 2007 through December 2008

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%

Table 6-10 Impact of $12 adder to cost based regulation offer: December 2008 through December 2009

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	4%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	2%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	2%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	3%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3%
Total				$247,893,142	$6,189,406	2.5%

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule

			New Rule		Old Rule			
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for Opportunity Cost	Using Lesser Schedule For Opportunity Costs, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for Opportunity Costs	Using Current Dispatch Schedule for Opportunity Costs, Total Charges	Additional Regulation Credits Paid Using New Rule	Pecentage Increase in Regulation Credits
2008	Dec	912	$24.79	$25,608,465	$22.50	$24,039,842	$1,568,623	6%
2009	Jan	970	$21.04	$26,614,105	$17.62	$24,136,240	$2,477,865	9%
2009	Feb	905	$25.83	$20,972,293	$17.10	$16,257,318	$4,714,975	22%
2009	Mar	819	$19.90	$17,618,413	$16.34	$15,645,792	$1,972,621	11%
2009	Apr	762	$16.84	$12,171,811	$13.93	$10,569,368	$1,602,443	13%
2009	May	738	$32.41	$21,166,797	$24.63	$16,514,576	$4,652,221	22%
2009	Jun	884	$32.59	$24,566,721	$23.08	$17,198,351	$7,368,370	30%
2009	Jul	908	$24.10	$20,065,104	$15.33	$12,992,257	$7,072,847	35%
2009	Aug	998	$23.89	$23,010,216	$14.18	$15,047,460	$7,962,756	35%
2009	Sep	803	$20.09	$15,216,790	$13.72	$10,656,302	$4,560,488	30%
2009	Oct	744	$17.20	$12,882,665	$13.62	$11,167,730	$1,714,935	13%
2009	Nov	779	$14.06	$10,695,843	$10.83	$9,230,018	$1,465,825	14%
2009	Dec	781	$17.75	$17,303,919	$11.71	$16,974,055	$329,864	2%
Total				$247,893,142		$200,429,309	$47,463,833	19%

Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2009

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1%
2009	Jan	$127,036	$26,614,105	0%
2009	Feb	$220,460	$20,972,293	1%
2009	Mar	$79,726	$17,618,413	0%
2009	Apr	$8,893	$12,171,811	0%
2009	May	$182,624	$21,166,797	1%
2009	Jun	$274,916	$24,566,721	1%
2009	Jul	$191,538	$20,065,104	1%
2009	Aug	$267,116	$23,010,216	1%
2009	Sep	$252,136	$15,216,790	2%
2009	Oct	$169,130	$12,882,665	1%
2009	Nov	$166,112	$10,695,843	2%
2009	Dec	$104,496	$17,303,919	1%
Total		$2,297,348	$247,893,142	1%

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through December 2009

			Increasing Markup from $7.50 to $12.00		Opportunity Cost Calculated Using Lower of Price Based or Cost Based Price		Regulation Credits Above Cost Plus Opportunity Costs no Longer Offset Against Operating Reserves		Changes for Three Pivotal Supplier Testing, December 1, 2008 - Summary	
Year	Month	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50	Additional Regulation Credits Paid Due to New Opportunity Cost Calculation	Percentage Increase in Regulation Credits Due to New Opportunity Cost Calculation	Balancing Operating Reserve Credits No Longer Offset	Percent of Regulation Credits No Longer Offsetting Operating Reserves	Total Additional Generator Credits	Total Percent of Regulation Credits Additional
2008	Dec	$25,608,465	$890,749	3%	$1,568,623	6%	$253,165	1%	$2,712,537	11%
2009	Jan	$26,614,105	$813,654	3%	$2,477,865	9%	$127,036	0%	$3,418,555	13%
2009	Feb	$20,972,293	$734,061	4%	$4,714,975	22%	$220,460	1%	$5,669,496	27%
2009	Mar	$17,618,413	$316,889	2%	$1,972,621	11%	$79,726	0%	$2,369,236	13%
2009	Apr	$12,171,811	$258,778	2%	$1,602,443	13%	$8,893	0%	$1,870,114	15%
2009	May	$21,166,797	$265,494	1%	$4,652,221	22%	$182,624	1%	$5,100,339	24%
2009	Jun	$24,566,721	$312,979	1%	$7,368,370	30%	$274,916	1%	$7,956,265	32%
2009	Jul	$20,065,104	$414,408	2%	$7,072,847	35%	$191,538	1%	$7,678,793	38%
2009	Aug	$23,010,216	$369,407	2%	$7,962,756	35%	$267,116	1%	$8,599,279	37%
2009	Sep	$15,216,790	$497,484	3%	$4,560,488	30%	$252,136	2%	$5,310,108	35%
2009	Oct	$12,882,665	$445,635	3%	$1,714,935	13%	$169,130	1%	$2,329,700	18%
2009	Nov	$10,695,843	$269,283	3%	$1,465,825	14%	$166,112	2%	$1,901,220	18%
2009	Dec	$17,303,919	$600,585	3%	$329,864	2%	$104,496	1%	$1,034,945	6%
Total		$247,893,142	$6,189,406	2.5%	$47,463,833	19%	$2,297,348	1%	$55,950,587	23%

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2009

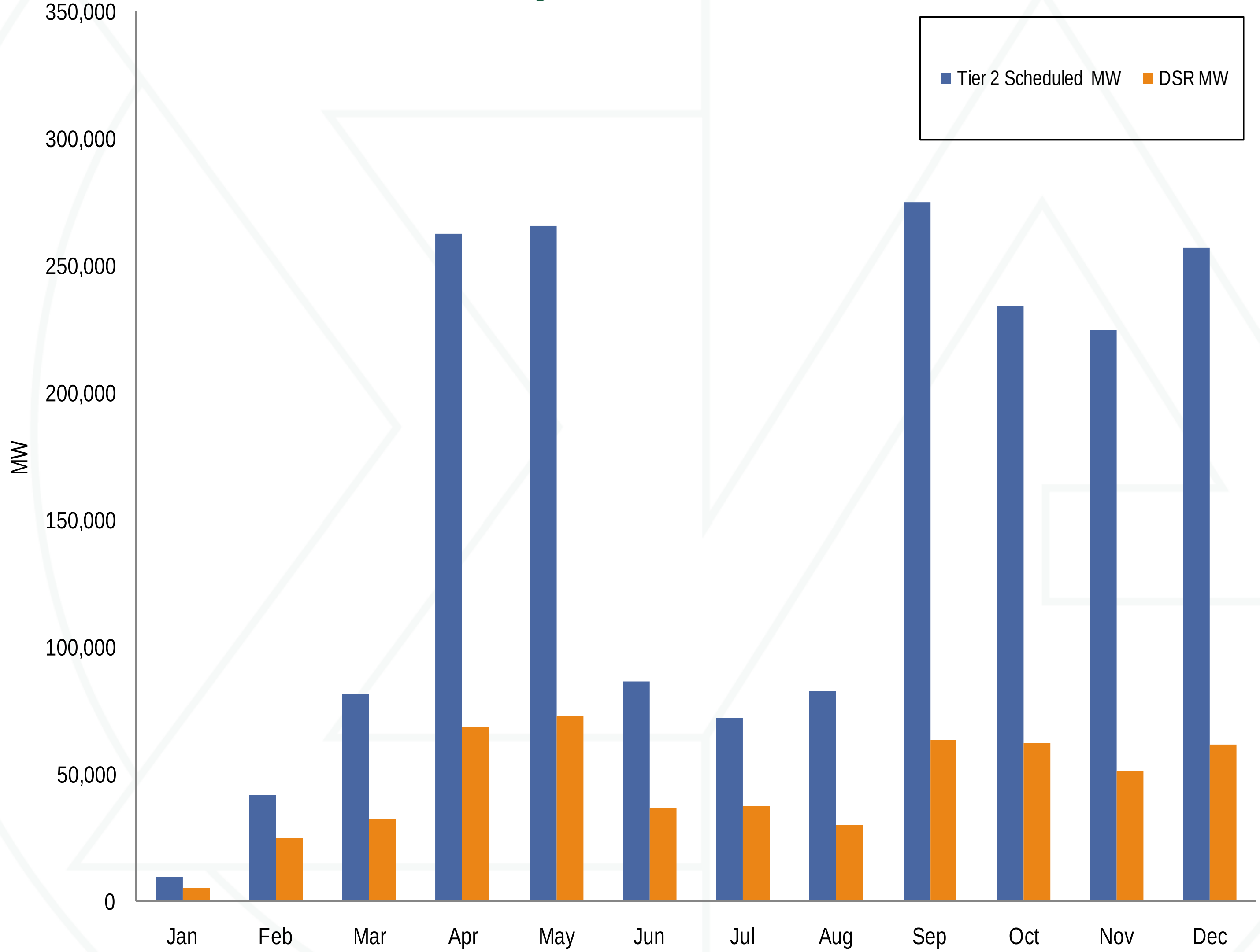

Table 6-17 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Puchased	Total DASR Credits
Jan	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578
Jul	6,071	$0.00	$0.50	$0.04	4,191,307	$155,790
Aug	6,725	$0.00	$4.00	$0.13	4,773,330	$620,430
Sep	5,438	$0.00	$0.42	$0.02	3,764,923	$77,945
Oct	5,023	$0.00	$0.42	$0.03	3,610,812	$102,984
Nov	5,188	$0.00	$0.42	$0.03	3,556,557	$113,027
Dec	5,992	$0.00	$0.50	$0.05	3,921,732	$191,599

Table 6-18 Black Start yearly zonal charges for network transmission use

Zone	Network Charges
AECO	$408,761
AEP	$737,082
AP	$136,340
BGE	$483,019
ComEd	$6,826,137
DAY	$146,531
DLCO	$26,736
DPL	$361,745
JCPL	$437,556
Met-Ed	$406,825
PECO	$726,207
PENELEC	$337,079
Pepco	$223,548
PPL	$122,610
PSEG	$949,280

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2009

	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%
Total	$9,591		$150,587	6%

Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2009 to 2010

		FTR Direction		
Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Physical	Yes	36.7%	5.9%	29.6%
	No	24.4%	36.8%	27.3%
	Total	61.2%	42.7%	56.9%
Financial	No	38.8%	57.3%	43.1%
Total		100.0%	100.0%	100.0%

Figure 8-11 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 through December 31, 2009

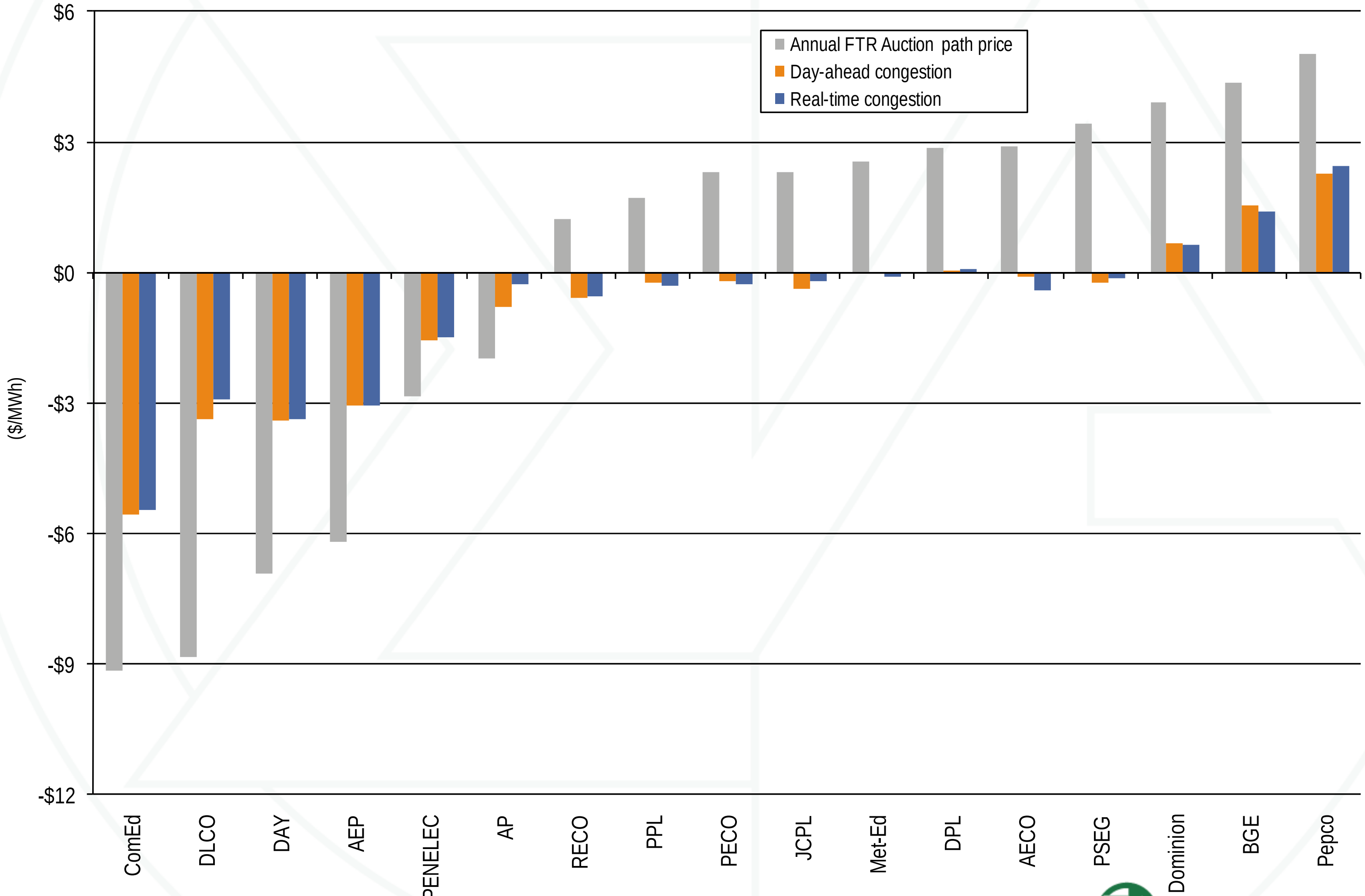

Table 8-27 ARR and FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$31,771,370	$36,858,894	$32,933,548	$35,696,716	$43,970,115	($8,273,399)	81.2%
AEP	$286,629,442	$209,802,906	$204,085,063	$292,347,285	$155,842,889	$136,504,396	>100%
AP	$786,115,867	$527,925,980	$780,244,128	$533,797,719	$298,746,849	$235,050,870	>100%
BGE	$98,283,955	$38,944,903	$57,160,496	$80,068,362	$89,929,323	($9,860,961)	89.0%
ComEd	$24,695,477	($26,152,262)	($4,320,075)	$2,863,290	$264,565,267	($261,701,977)	1.1%
DAY	$9,926,586	$1,744,872	($2,026,571)	$13,698,029	$5,493,146	$8,204,883	>100%
DLCO	$4,691,151	($9,342,004)	($16,286,386)	$11,635,533	$14,972,671	($3,337,138)	77.7%
Dominion	$463,320,908	$344,212,309	$522,524,367	$285,008,850	$254,898,027	$30,110,823	>100%
DPL	$28,077,406	$50,222,866	$42,813,893	$35,486,379	$79,599,656	($44,113,277)	44.6%
JCPL	$98,171,902	$5,730,251	$104,255,372	($353,219)	$92,985,545	($93,338,764)	<0%
Met-Ed	$50,979,701	$36,542,204	$60,190,813	$27,331,092	($1,271,642)	$28,602,734	>100%
PECO	$75,104,737	$65,545,964	$76,721,387	$63,929,314	($47,350,955)	$111,280,269	>100%
PENELEC	$95,333,189	$118,697,998	$134,333,128	$79,698,059	$112,271,697	($32,573,638)	71.0%
Pepco	$59,162,442	$204,600,376	$260,910,557	$2,852,261	$150,501,458	($147,649,197)	1.9%
PJM	$20,562,228	($3,803,359)	$2,995,857	$13,763,012	($119,445,094)	$133,208,106	>100%
PPL	$73,844,704	$74,910,276	$82,036,315	$66,718,665	$4,627,831	$62,090,834	>100%
PSEG	$154,621,742	$71,755,534	$148,376,631	$78,000,645	$15,850,146	$62,150,499	>100%
RECO	$0	$3,877	$2,660,947	($2,657,070)	$5,941,446	($8,598,516)	<0%
Total	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,422,128,376	$197,756,546	>100%

Monitoring Analytics

Table 8-28 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010*	$747,598,320	$388,741,220	$799,140,566	$337,198,974	$360,608,751	($23,409,777)	93.5%

* Shows seven months ended 31-Dec-09

Market Monitoring Unit

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