State of the PJM Market
January through February, 2010

PJM Members Committee

May 6, 2009

Joseph Bowring

Monitoring Analytics

Table 1-1 Total price per MWh: January through February 2010

Category	$/MWh	Percent
Load Weighted Energy	$50.00	75.6%
Capacity	$10.42	15.7%
Transmission Service Charges	$3.66	5.5%
Operating Reserves (Uplift)	$0.70	1.1%
Reactive	$0.38	0.6%
Regulation	$0.37	0.6%
PJM Administrative Fees	$0.34	0.5%
Transmission Enhancement Cost Recovery	$0.12	0.2%
Transmssion Owner (Schedule 1A)	$0.08	0.1%
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	$0.01	0.0%
Transmission Facility Charges	$0.00	0.0%
Total	$66.17	100.0%

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

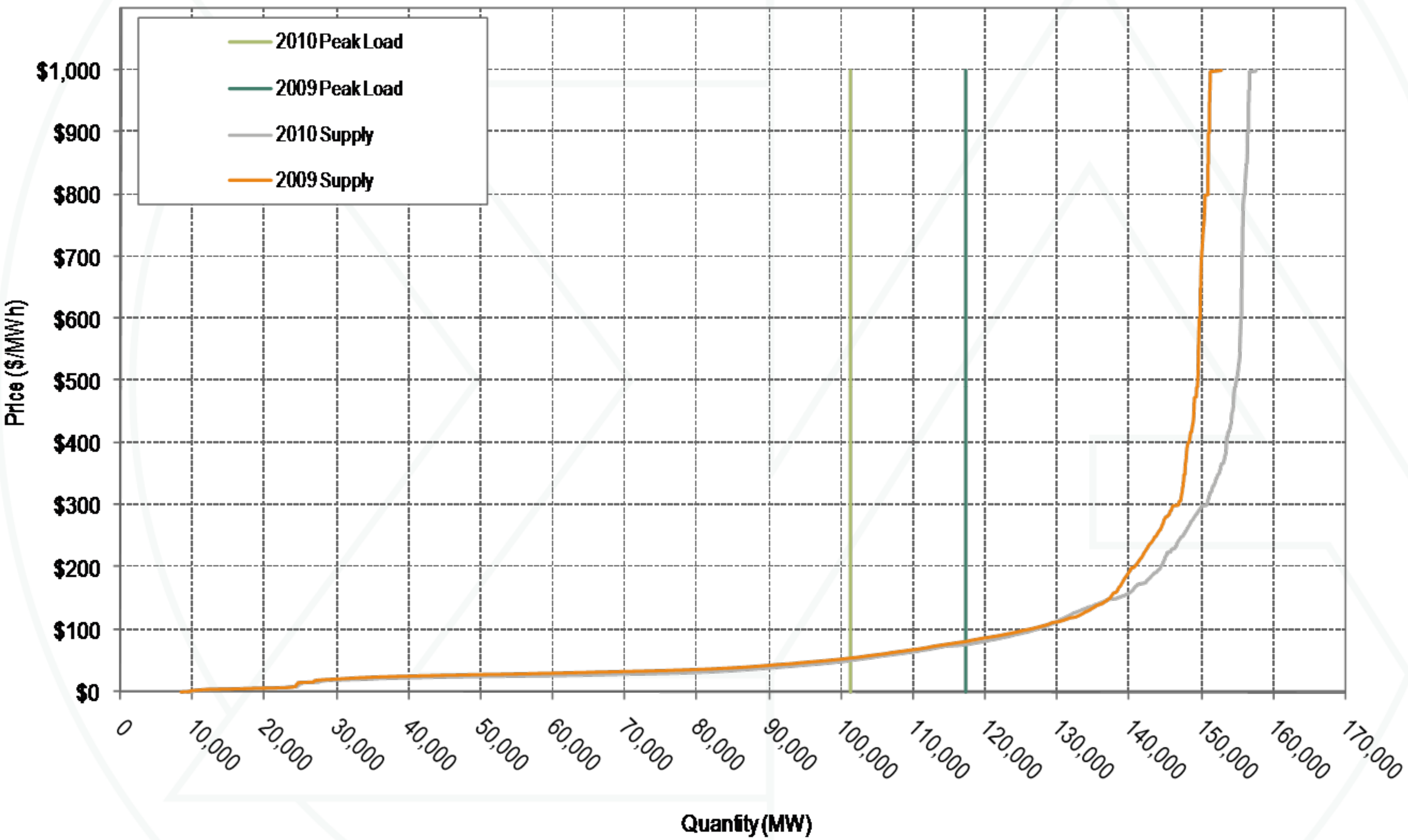

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Figure 2-3 PJM peak-load comparison: Jan-Feb Peak 2009 vs. Jan-Feb Peak 2010

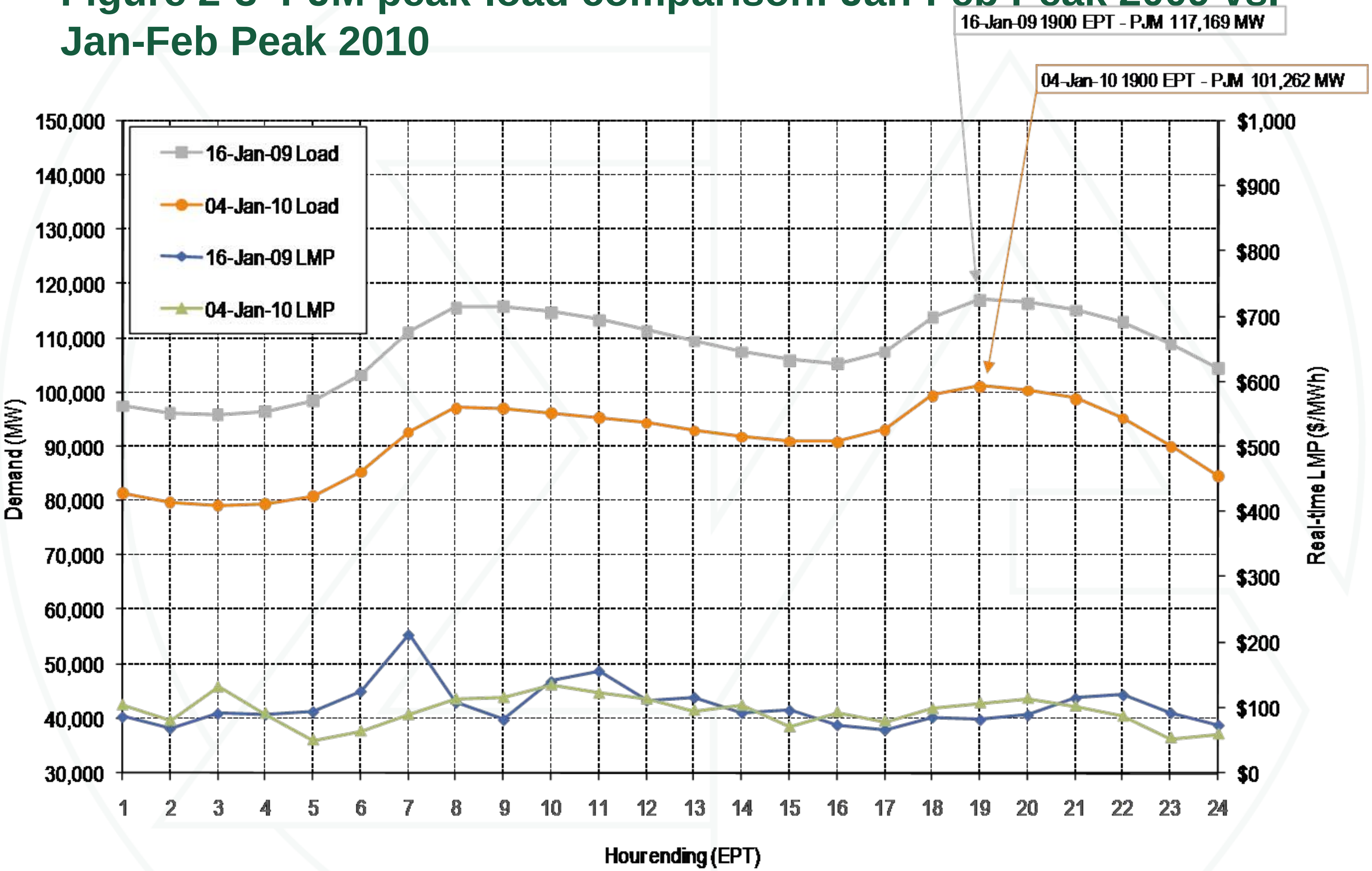

Table 2-4 Annual offer-capping statistics: Calendar years 2005 to February 2010

	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%
2010	0.5%	0.1%	0.2%	0.0%

Table 2-5 Offer-capped unit statistics: January through February 2010

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2009 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	30
80% and < 90%	0	0	0	0	0	10
75% and < 80%	0	0	0	0	0	4
70% and < 75%	0	0	1	0	0	2
60% and < 70%	0	0	0	1	0	13
50% and < 60%	0	0	0	0	0	22
25% and < 50%	0	0	0	0	0	21
10% and < 25%	0	0	0	0	0	24

Table 2-33 Type of fuel used (By real-time marginal units): January through February 2010

Fuel Type	2010
Coal	68%
Natural Gas	27%
Wind	3%
Petroleum	1%
Landfill Gas	1%
Misc	0%

Table 2-47 Frequently mitigated units and associated units (By month): January through February 2010

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	35	31	27	93
February	35	28	31	94

Table 2-49 PJM real-time average load: Calendar years 1998 to February 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	85,619	86,054	8,900	12.6%	14.0%	(32.9%)

Figure 2-8 PJM real-time average load: Calendar years 2008 through February, 2010

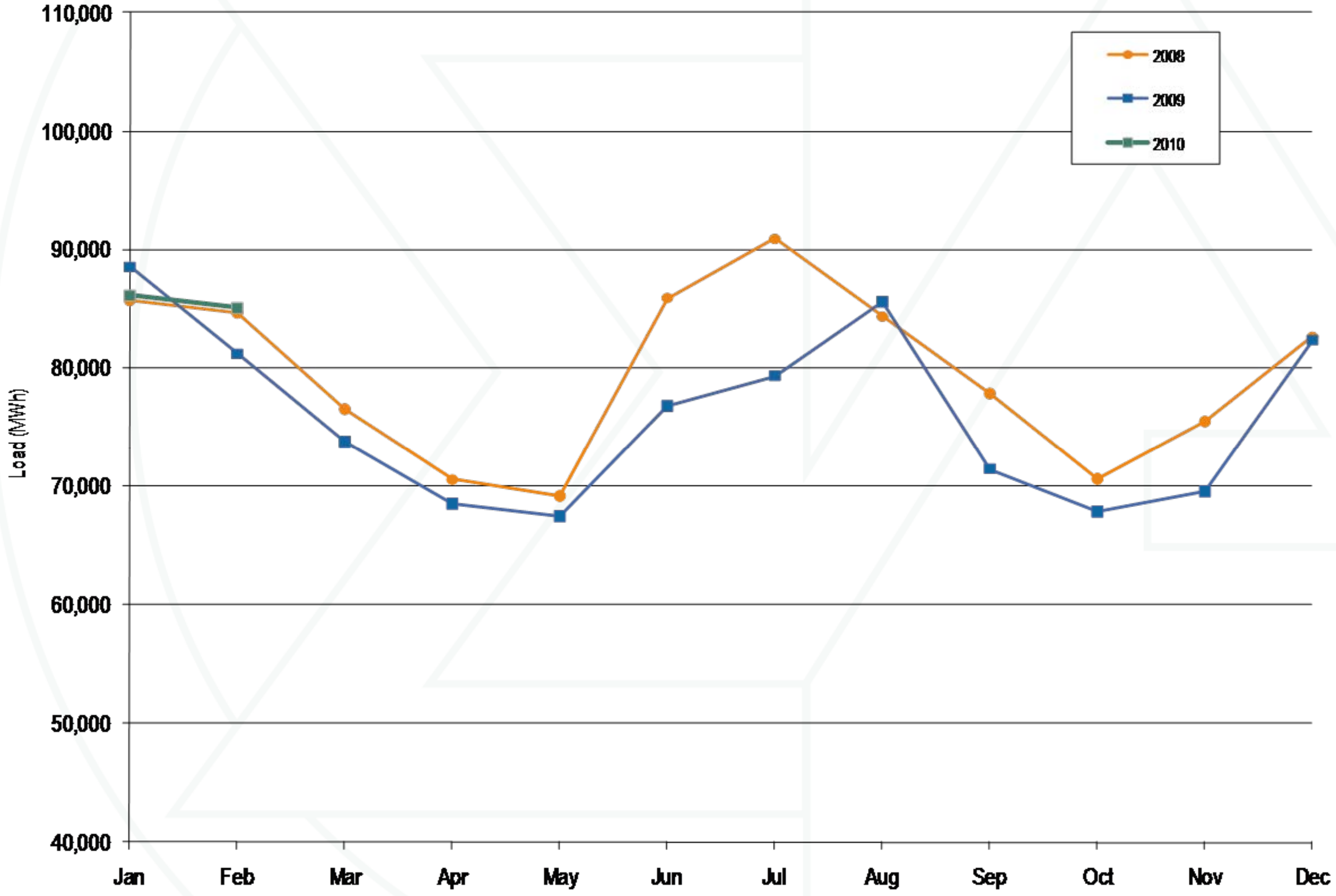

Table 2-59 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through February 2010

	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	$50.00	$41.74	$25.08	28.0%	21.9%	37.7%

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through February 2010

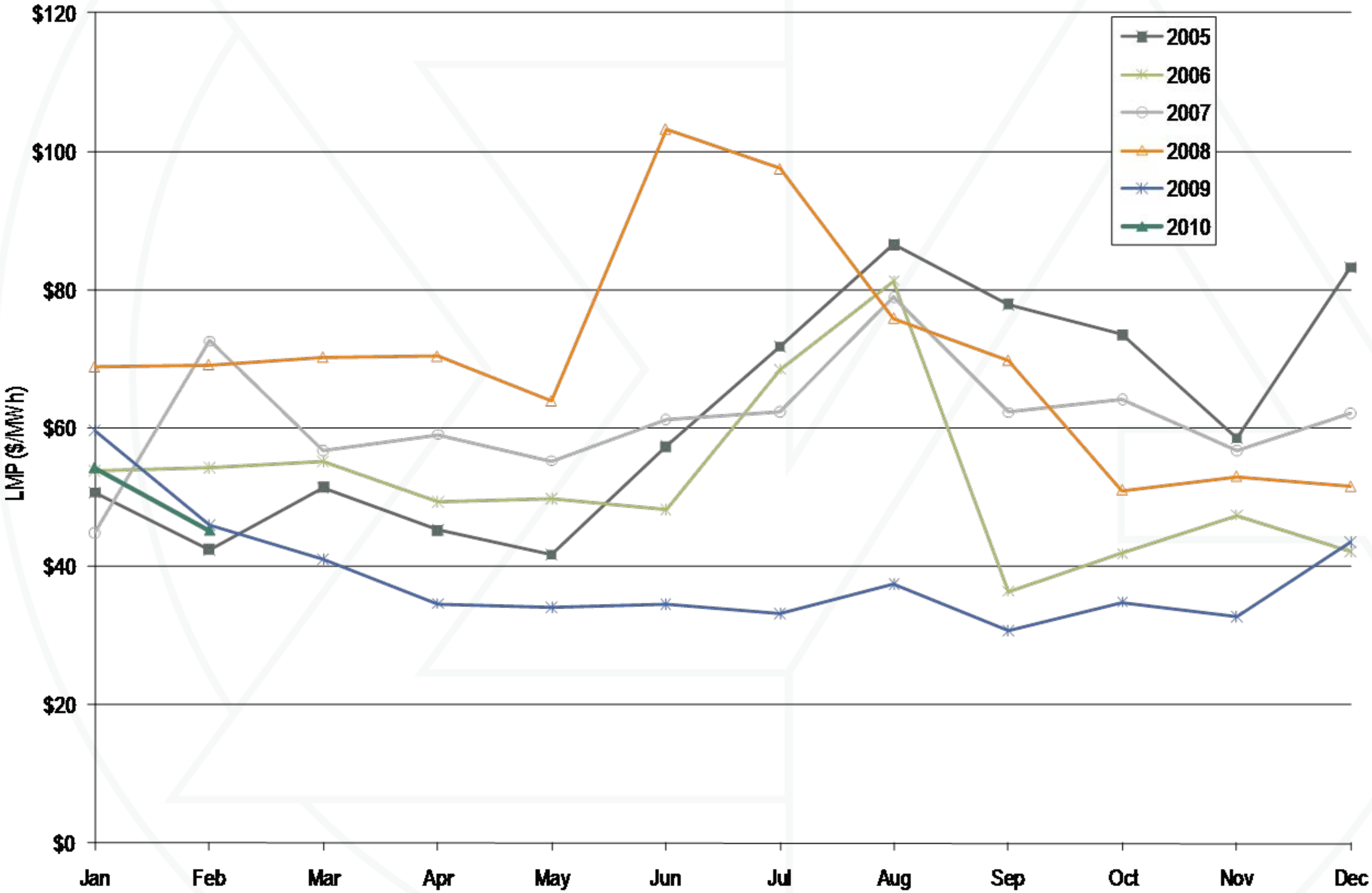

Figure 2-15 Spot average fuel price comparison: Calendar years 2008 through February 2010

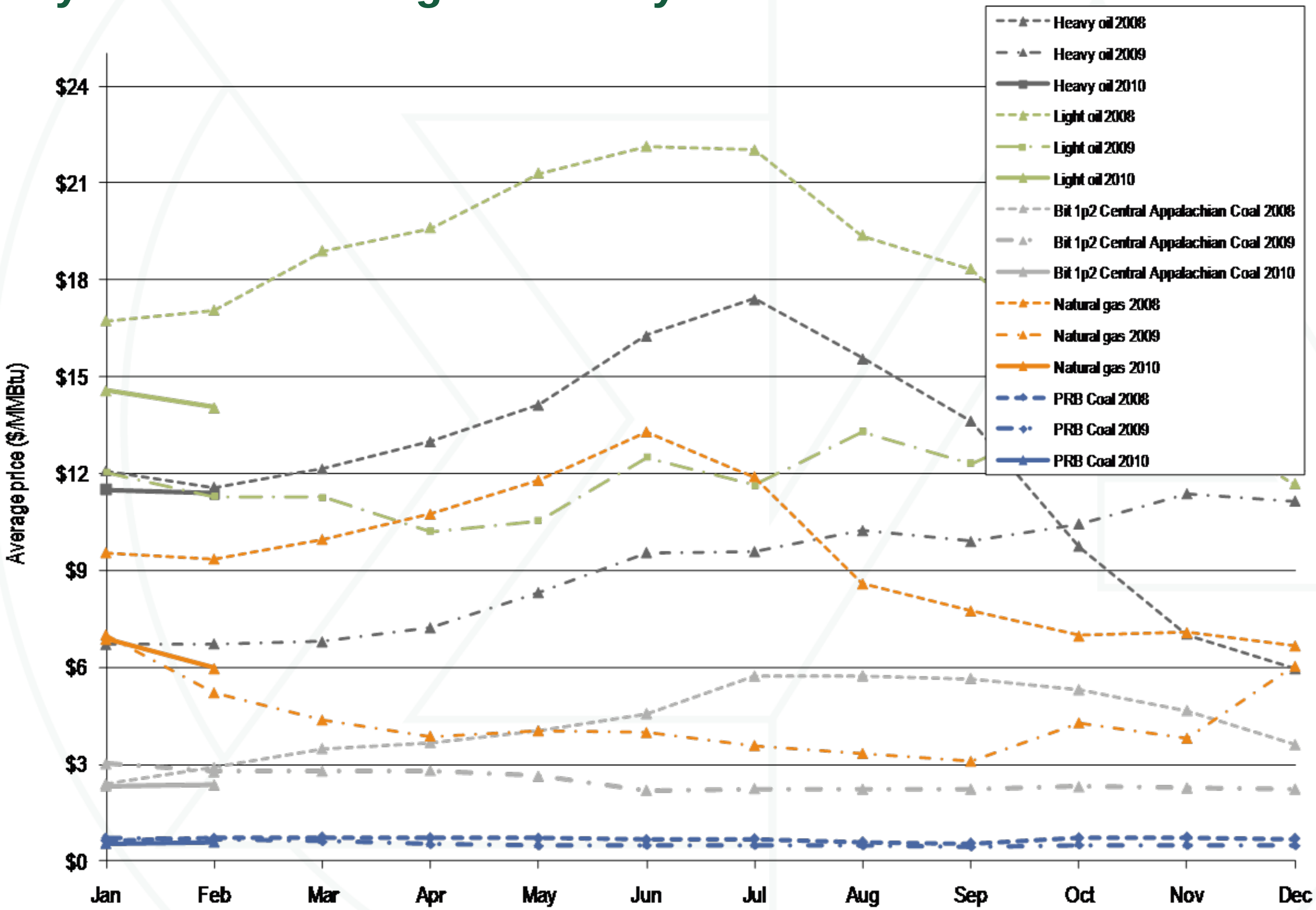

Figure 2-16 Spot average emission price comparison: Calendar years 2008 through February 2010

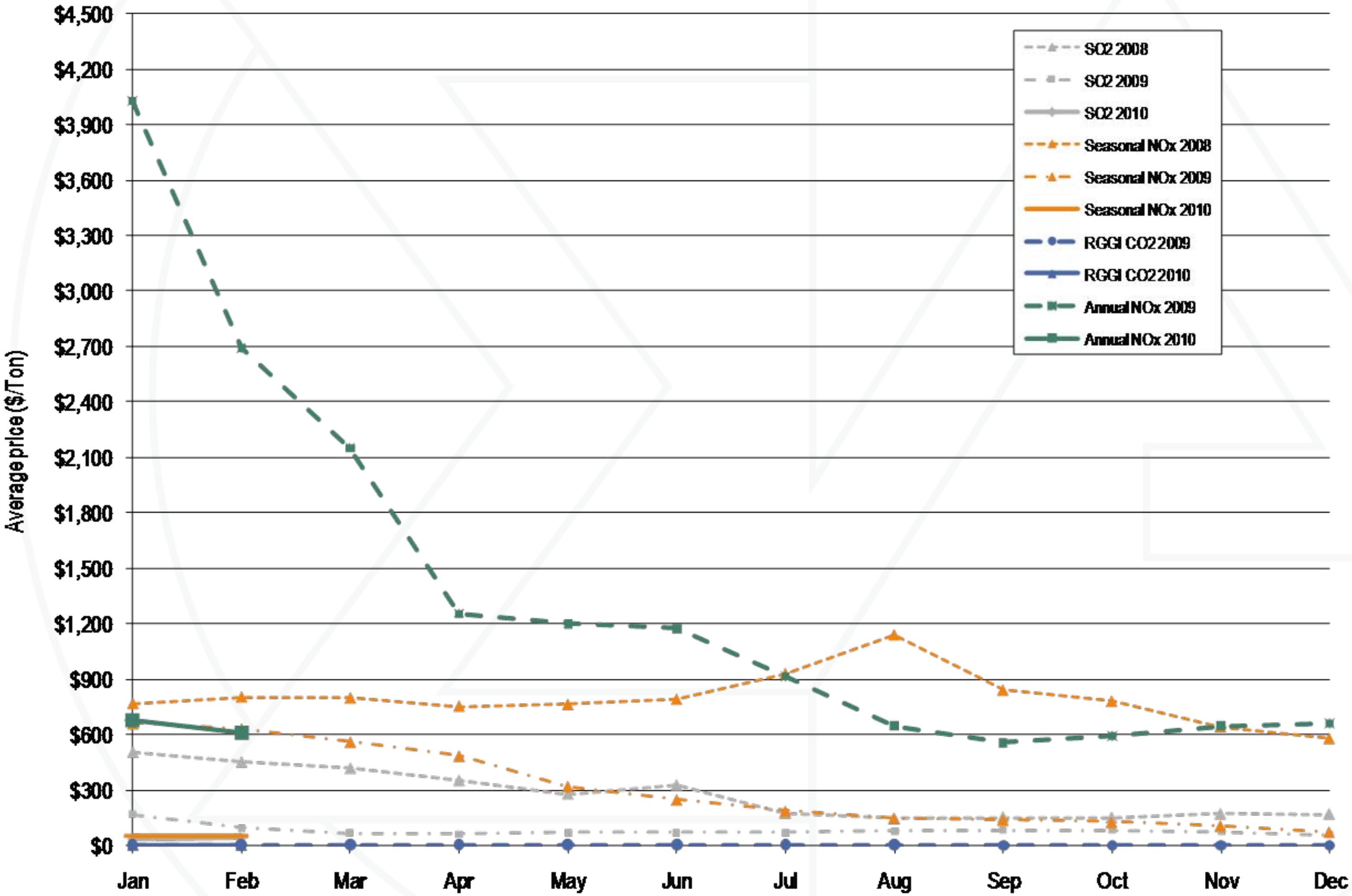

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Table 2-63 PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method: January through February 2009 and 2010

	2009 Load-Weighted LMP	2010 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.46	$30.87	(42.3%)

Table 2-64 Components of PJM real-time, annual, load-weighted, average LMP: January through February 2010

Element	Contribution to LMP	Percent
Coal	$21.32	42.6%
Gas	$20.64	41.3%
10% Cost Adder	$4.56	9.1%
VOM	$2.53	5.1%
Oil	$0.51	1.0%
CO2	$0.48	1.0%
SO2	$0.29	0.6%
Dispatch Differential	$0.15	0.3%
NA	$0.09	0.2%
Shadow Price Limit Adder	$0.04	0.1%
FMU Adder	$0.02	0.0%
M2M Adder	$0.01	0.0%
Municipal Waste	$0.00	0.0%
UDS Override Differential	($0.21)	(0.4%)
Markup	($0.43)	(0.9%)
LMP	$50.00	100.0%

Table 2-82 Monthly volume of cleared and submitted INCs, DECs: January through February 2010

	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	11,144	21,634	282	936	266	893	17,513	29,406
Feb	12,387	23,827	387	1,122	270	883	17,602	28,542
Mar								
Apr								
May								
Jun								
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	11,766	22,731	335	1,029	268	888	17,558	28,974

Table 2-84 PJM virtual bids by type of bid parent organization (MW): January through February 2010

	Category	Total Virtual Bids MW	Percentage
2010	Financial	18,458,529	30.6%
2010	**Physical**	**41,887,904**	**69.4%**
2010	Total	60,346,433	100%

Table 2-85 PJM virtual bids by top ten locations (MW): January through February 2010

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	8,853,275	12,246,504	21,099,779
N ILLINOIS HUB	HUB	1,329,757	1,285,013	2,614,770
AEP-DAYTON HUB	HUB	969,478	1,152,108	2,121,586
PPL	ZONE	107,146	1,491,382	1,598,528
PSEG	ZONE	159,217	1,021,437	1,180,654
BGE	ZONE	195,337	854,812	1,050,149
IMO	INTERFACE	537,602	382,620	920,222
MISO	INTERFACE	207,985	475,443	683,428
JCPL	ZONE	164,783	398,865	563,648
PEPCO	ZONE	317,777	235,337	553,114

Figure 2-19 PJM day-ahead aggregate supply curves: 2010 example day

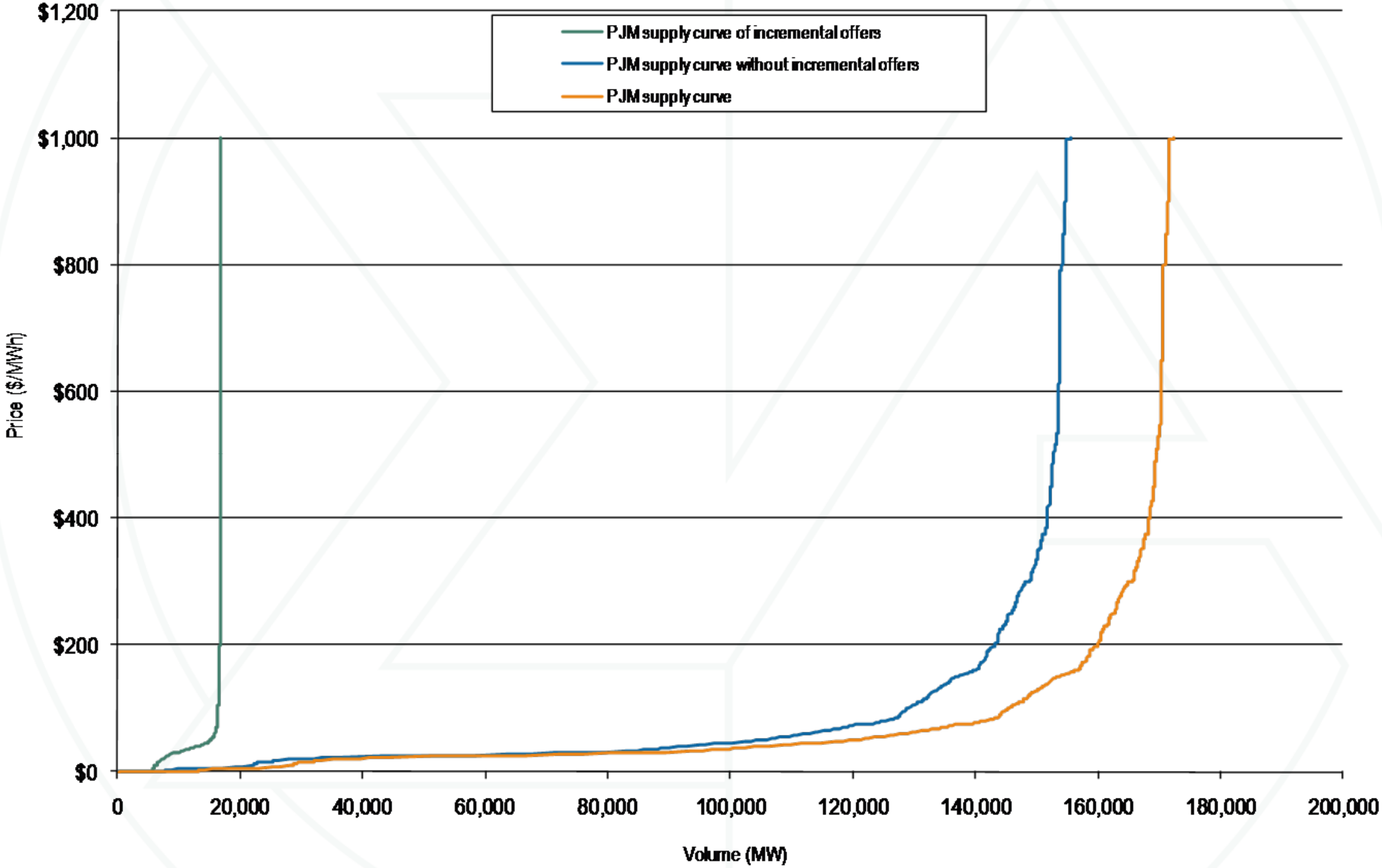

Table 2-87 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 through February 2010

	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%
2010	$51.21	$48.49	($2.72)	(5.6%)

Table 2-91 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar year 2009 through February 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%	11.9%	19.5%	68.6%	(0.8%)	4.2%	(3.4%)
Feb	**13.4%**	**14.5%**	**72.1%**	**13.3%**	**19.5%**	**67.2%**	**(0.1%)**	**5.0%**	**(4.9%)**
Mar	13.8%	16.7%	69.5%						
Apr	**13.5%**	**17.2%**	**69.3%**						
May	14.6%	18.8%	66.7%						
Jun	**12.5%**	**16.5%**	**71.0%**						
Jul	12.6%	16.9%	70.5%						
Aug	**11.7%**	**16.0%**	**72.3%**						
Sep	12.5%	18.1%	69.4%						
Oct	**13.0%**	**19.8%**	**67.2%**						
Nov	13.2%	19.0%	67.8%						
Dec	**11.7%**	**16.8%**	**71.5%**						
Annual	12.9%	17.0%	70.1%	12.5%	19.5%	67.9%	(0.3%)	2.5%	(2.2%)

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 3-36 PJM installed capacity (By fuel source): January 1 2009, May 31 2009, June 1 2009, December 31 2009, January 1, 2010, and February 28, 2010

	1-Jan-09		31-May-09		1-Jun-09		31-Dec-09		1-Jan-10		28-Feb-10	
	MW	Percent	MW	Percent	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%	68,382.1	40.7%	68,273.2	40.7%
Gas	**48,333.9**	**29.3%**	**48,506.9**	**29.4%**	**48,979.3**	**29.2%**	**48,838.8**	**29.2%**	**49,238.8**	**29.3%**	**49,234.0**	**29.4%**
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%	7,921.9	4.7%	7,897.9	4.7%
Nuclear	**30,478.0**	**18.5%**	**30,542.5**	**18.5%**	**30,701.5**	**18.3%**	**30,731.5**	**18.4%**	**30,611.9**	**18.2%**	**30,599.9**	**18.2%**
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%	10,700.1	6.4%	10,699.0	6.4%
Solid waste	**664.7**	**0.4%**	**664.7**	**0.4%**	**672.1**	**0.4%**	**672.1**	**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%	326.9	0.2%	338.9	0.2%
Total	**164,898.9**	**100.0%**	**165,146.7**	**100.0%**	**167,453.9**	**100.0%**	**167,326.4**	**100.0%**	**167,853.8**	**100.0%**	**167,715.0**	**100.0%**

Table 3-37 PJM generation (By fuel source (GWh)): January through February 2010

		GWh	Percent
Coal		68,171.0	54.6%
Nuclear		**42,480.4**	**34.0%**
Gas		8,856.5	7.1%
	Natural Gas	8,606.3	6.9%
	Landfill Gas	250.1	0.2%
	Biomass Gas	0.1	0.0%
Hydroelectric		**2,737.3**	**2.2%**
Waste		810.3	0.6%
	Solid Waste	594.5	0.5%
	Miscellaneous	215.8	0.2%
Wind		**1,620.6**	**1.3%**
Oil		86.6	0.1%
	Heavy Oil	62.1	0.0%
	Light Oil	20.9	0.0%
	Diesel	3.4	0.0%
	Kerosene	0.2	0.0%
	Jet Oil	0.0	0.0%
Solar		**0.5**	**0.0%**
Battery		0.1	0.0%
Total		**124,763.1**	**100.0%**

Table 3-47 Capacity factor of wind units in PJM: January through February 2010

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	26.5%	19,824	940
Capacity Resource	**36.0%**	**37,464**	**2,418**
All Units	33.2%	57,288	3,543

Table 3-48 Wind resources in real time offering at a negative price in PJM: January through February 2010

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	481.0	236	1.39%
All Wind	**1,309.0**	**397**	**2.34%**

Table 3-50 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load: January through February 2010

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	33.3%				33.3%
	Average Wind Generation	1,086.7				1,086.7
	Average Load	91,305.2				91,305.2
Off-Peak	Capacity Factor	33.1%				33.1%
	Average Wind Generation	1,078.9				1,078.9
	Average Load	80,380.7				80,380.7

Table 3-54 Monthly operating reserve charges: Calendar years 2009 and 2010

	2009 Charges				2010 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$9,260,150	$1,328,814	$30,116,725	$40,705,689	$10,281,351	$50,022	$40,308,020	$50,639,393
Feb	$7,434,068	$839,679	$16,548,988	$24,822,735	$11,425,494	$14,715	$22,365,749	$33,805,958
Mar	$9,549,963	$108,664	$26,025,562	$35,684,189	$0	$0	$0	$0
Apr	$6,998,364	$19,929	$13,251,273	$20,269,566	$0	$0	$0	$0
May	$6,024,108	$5,543	$15,490,257	$21,519,908	$0	$0	$0	$0
Jun	$6,722,329	$0	$19,339,846	$26,062,175	$0	$0	$0	$0
Jul	$8,210,636	$38,643	$17,728,976	$25,978,255	$0	$0	$0	$0
Aug	$7,697,174	$1	$21,164,586	$28,861,761	$0	$0	$0	$0
Sep	$6,057,598	$13,611	$13,471,368	$19,542,577	$0	$0	$0	$0
Oct	$7,046,301	$0	$17,026,425	$24,072,727	$0	$0	$0	$0
Nov	$8,617,280	$22,639	$12,888,600	$21,528,519	$0	$0	$0	$0
Dec	$11,323,263	$117,573	$25,353,409	$36,794,245	$0	$0	$0	$0
Total	$94,941,235	$2,495,097	$228,406,015	$325,842,346	$21,706,845	$64,737	$62,673,769	$84,445,351
Share of Annual Charges	29.1%	0.8%	70.1%	100.0%	25.7%	0.1%	74.2%	100.0%

Table 3-55 Regional balancing charges allocation: January through February 2010

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$9,281,436	$350,921	$9,632,357	$18,226,284	$11,423,189	$5,495,056	$35,144,528	$44,776,885
	18.3%	0.7%	19.0%	35.9%	22.5%	10.8%	69.3%	88.3%
East	$225,949	$9,197	$235,146	$997,178	$824,578	$241,115	$2,062,872	$2,298,018
	0.4%	0.0%	0.5%	2.0%	1.6%	0.5%	4.1%	4.5%
West	$2,514,769	$86,881	$2,601,650	$561,407	$279,560	$196,368	$1,037,334	$3,638,985
	5.0%	0.2%	5.1%	1.1%	0.6%	0.4%	2.0%	7.2%
Total	$12,022,154	$446,999	$12,469,153	$19,784,869	$12,527,326	$5,932,539	$38,244,734	$50,713,888
	23.7%	0.9%	24.6%	39.0%	24.7%	11.7%	75.4%	100%

Figure 3-14 Daily RTO reliability and deviation rates ($/MWh): January through February 2010

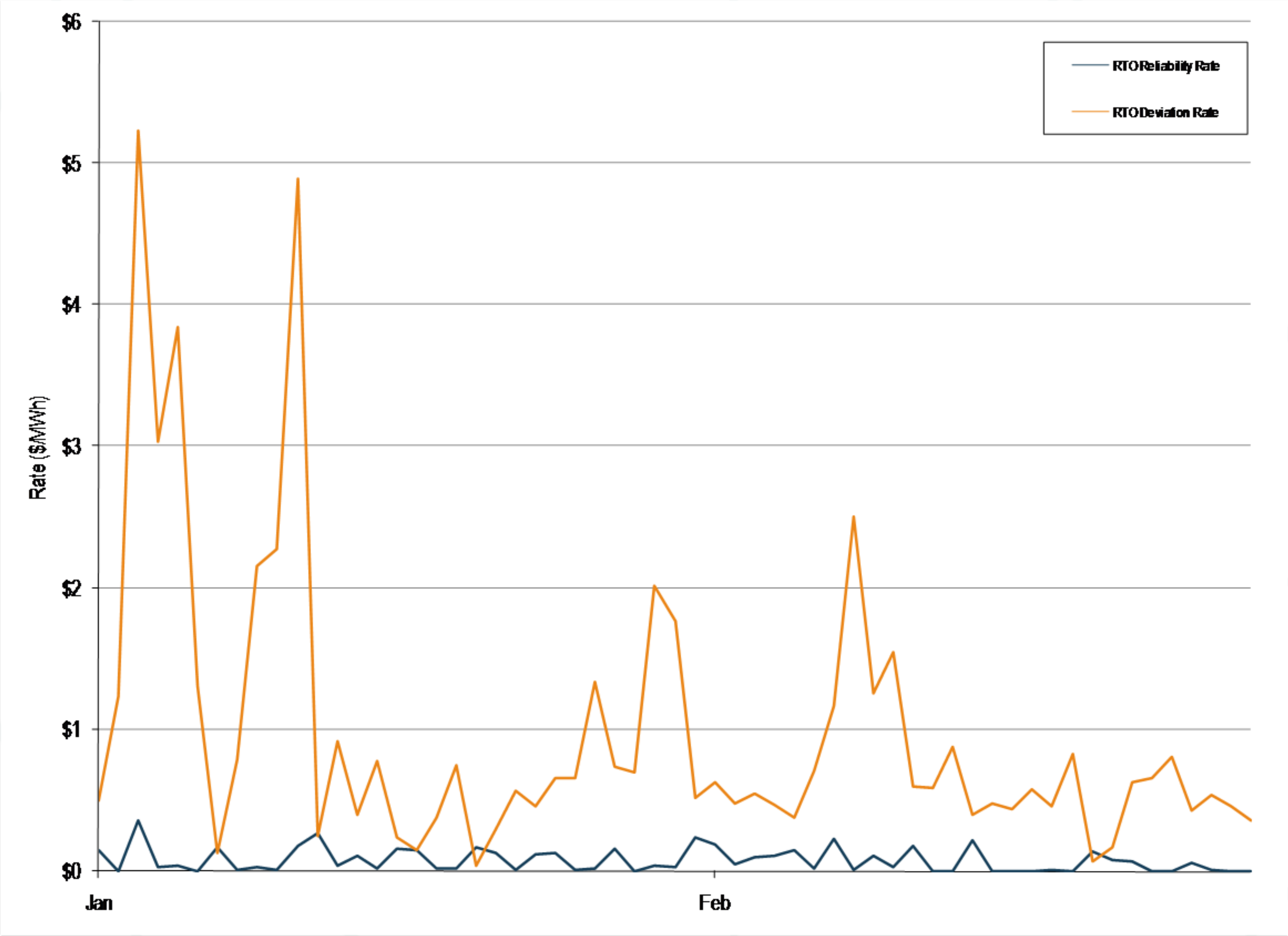

Figure 3-15 Daily regional reliability and deviation rates ($/MWh): January through February 2010

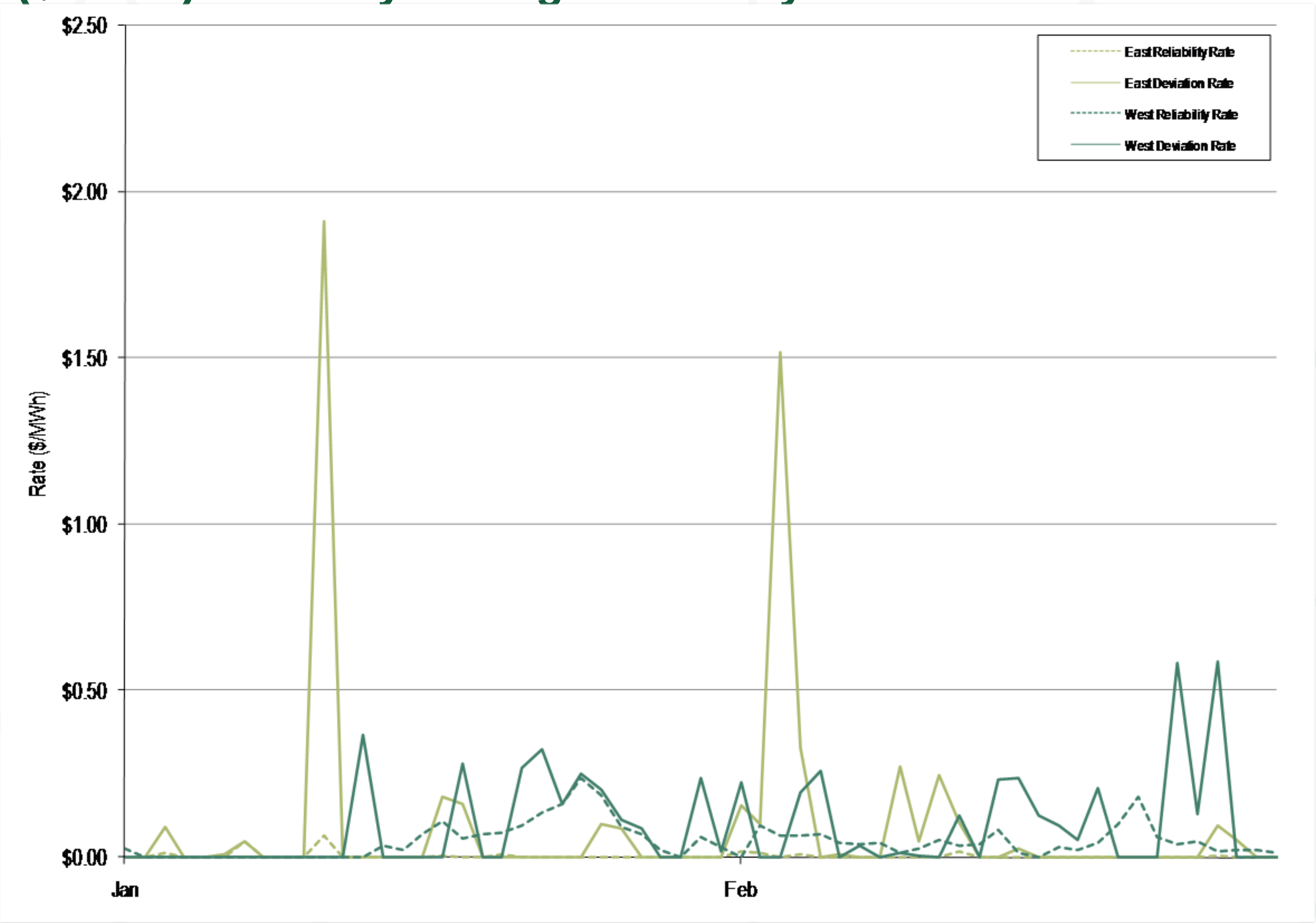

Figure 3-16 Operating reserve credits: January through February 2010

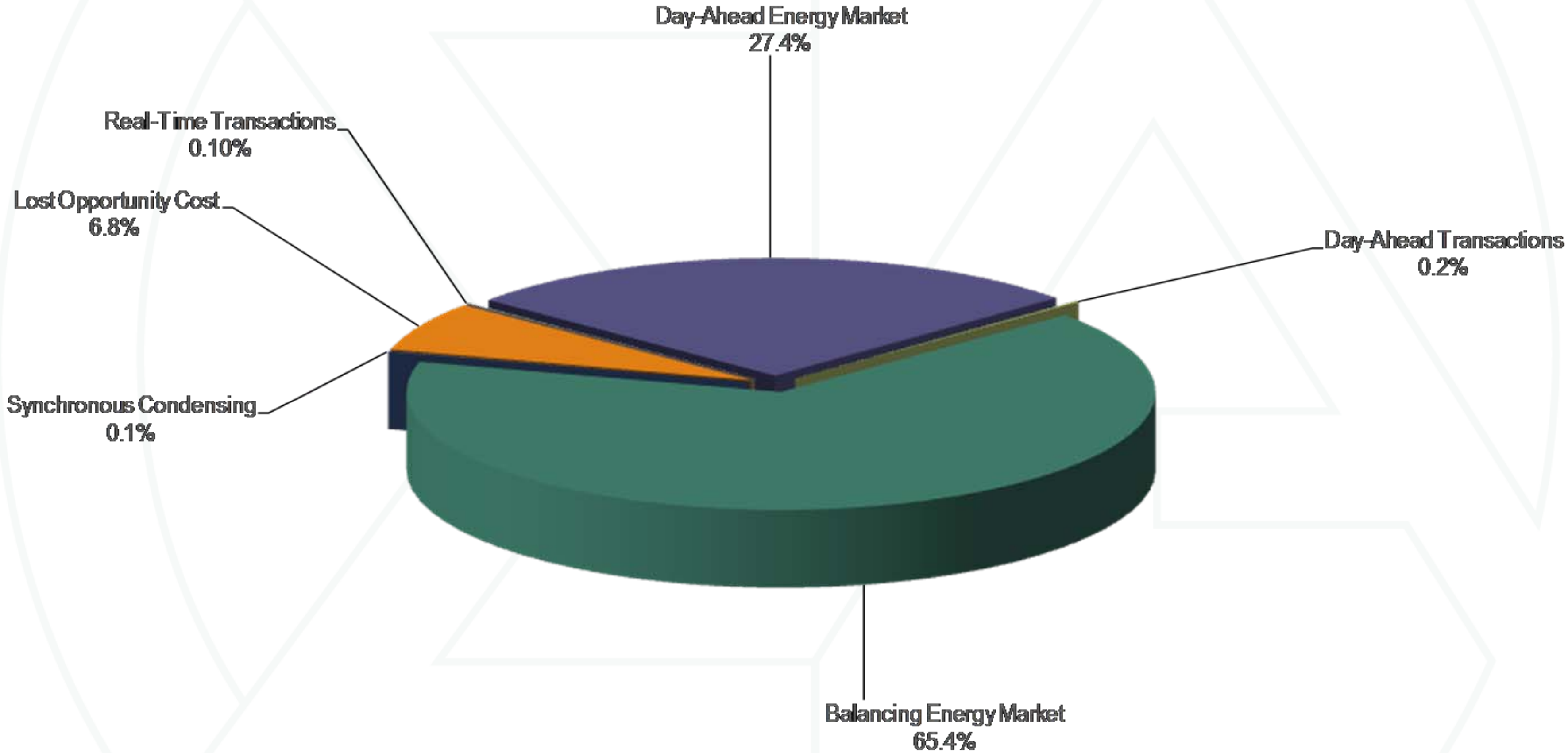

Table 3-60 Credits by operating reserve market (By unit type): January through February 2010

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	37.9%	0.0%	60.5%	1.6%	$43,425,348
Combustion Turbine	0.3%	0.5%	95.1%	4.1%	$14,045,206
Diesel	0.0%	0.0%	96.7%	3.3%	$32,852
Hydro	0.0%	0.0%	100.0%	0.0%	$3,539
Landfill	0.0%	0.0%	0.0%	100.0%	$3,052,251
Nuclear	0.0%	0.0%	0.0%	0.0%	$0
Steam	28.8%	0.0%	67.2%	4.1%	$17,583,496
Wind Farm	0.0%	0.0%	2.8%	97.2%	$286,658

Table 3-70 Difference in total charges between old rules and new rules: January through February 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	$26,047,110	$16,801,829	$7,864,949	$50,713,888
Charges (Current)	$12,022,154	$446,999	$12,469,153	$19,784,869	$12,527,326	$5,932,539	$38,244,734
Difference	$12,022,154	$446,999	$12,469,153	($6,262,241)	($4,274,502)	($1,932,410)	($12,469,153)

Table 3-71 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): January through February 2010

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047
Feb	8,323,844	11,828,780	2,004,162	2,234,045
Total	16,615,276	24,858,296	4,468,014	5,686,092

Table 3-72 Comparison of balancing operating reserve charges to virtual bids: January through February 2010

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$10,131,402	$12,596,576	($2,465,174)
Feb	$3,939,289	$5,368,599	($1,429,310)
Total	$14,070,690	$17,965,175	($3,894,485)

Table 3-73 Summary of impact on virtual bids under balancing operating reserve allocation: January through February 2010

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Current Rules	Balancing Rate Under Old Rules	Charges Under Current Rules	Charges Under Old Rules	Differerence
RTO	4,468,014	5,686,092	10,154,106	1.14	1.61	$13,064,033	$17,965,175	($4,901,142)
East	3,063,645	3,303,533	6,367,178	0.10	0.00	$676,631	$0	$676,631
West	1,382,444	2,348,976	3,731,420	0.09	0.00	$330,027	$0	$330,027

Table 3-74 Impact of segmented make whole payments: December 2008 through February 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	$32,822,043	$33,772,219	$950,176
2010	Feb	$17,343,775	$17,631,590	$287,815
Total		$249,467,865	$258,880,263	$9,412,397

Table 3-78 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through February 2010

Unit Type	Share of Increase
Combined-Cycle	47.3%
Steam	5.2%
Combustion Turbines	47.5%
Diesel	0.0%

Table 3-81 Top 10 units and organizations receiving total operating reserve credits: January through February 2010

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$16,850,928	21.5%	21.5%	$38,566,981	49.1%	49.1%
2	$11,345,345	14.5%	35.9%	$5,740,798	7.3%	56.5%
3	$3,170,146	4.0%	40.0%	$4,576,534	5.8%	62.3%
4	$2,403,186	3.1%	43.0%	$4,083,323	5.2%	67.5%
5	$1,432,259	1.8%	44.9%	$3,313,644	4.2%	71.7%
6	$1,418,148	1.8%	46.7%	$3,170,146	4.0%	75.8%
7	$1,413,697	1.8%	48.5%	$2,644,548	3.4%	79.1%
8	$1,233,637	1.6%	50.0%	$1,470,753	1.9%	81.0%
9	$1,198,615	1.5%	51.6%	$1,410,670	1.8%	82.8%
10	$989,772	1.3%	52.8%	$1,211,435	1.5%	84.3%

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

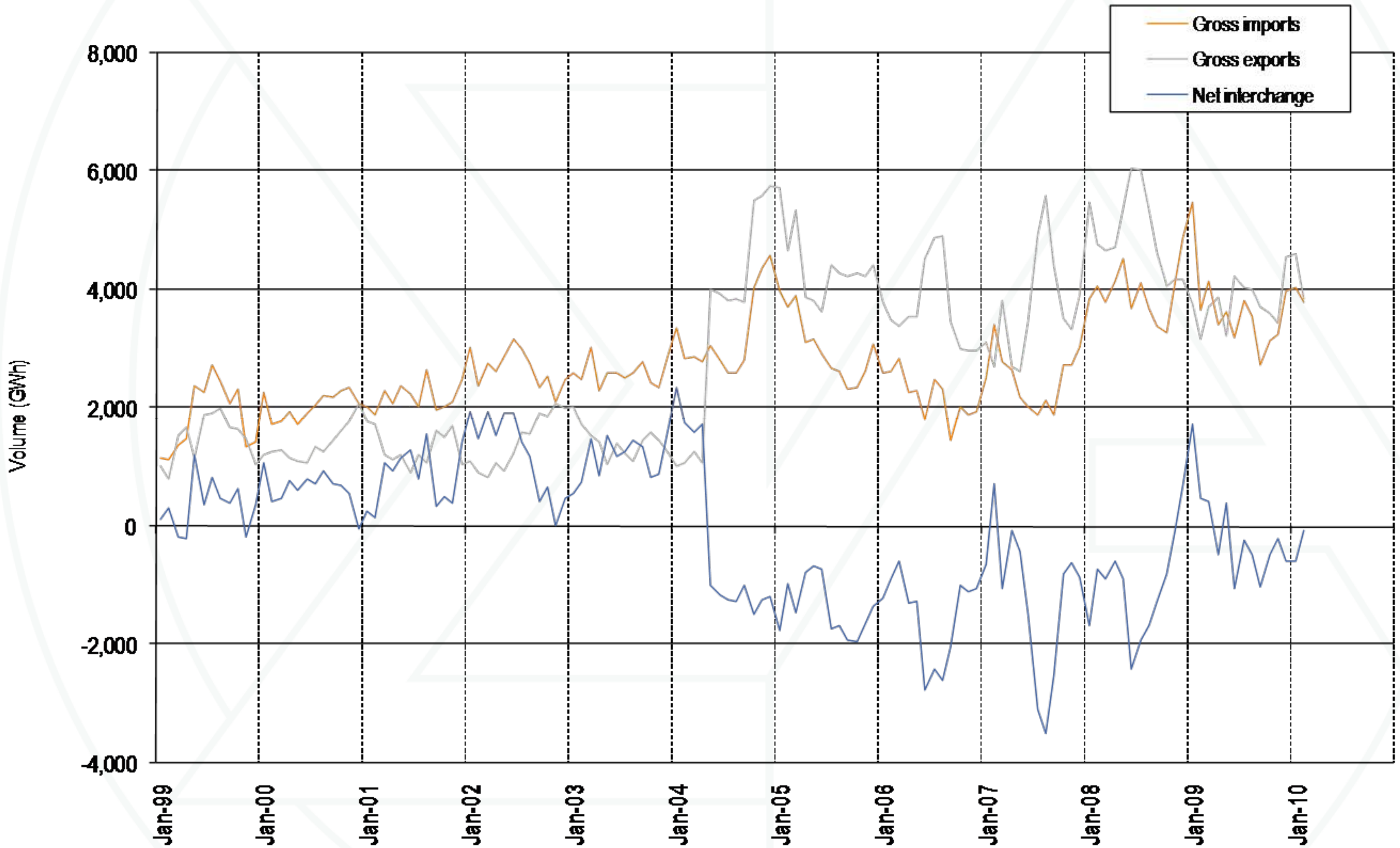

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through February 2010

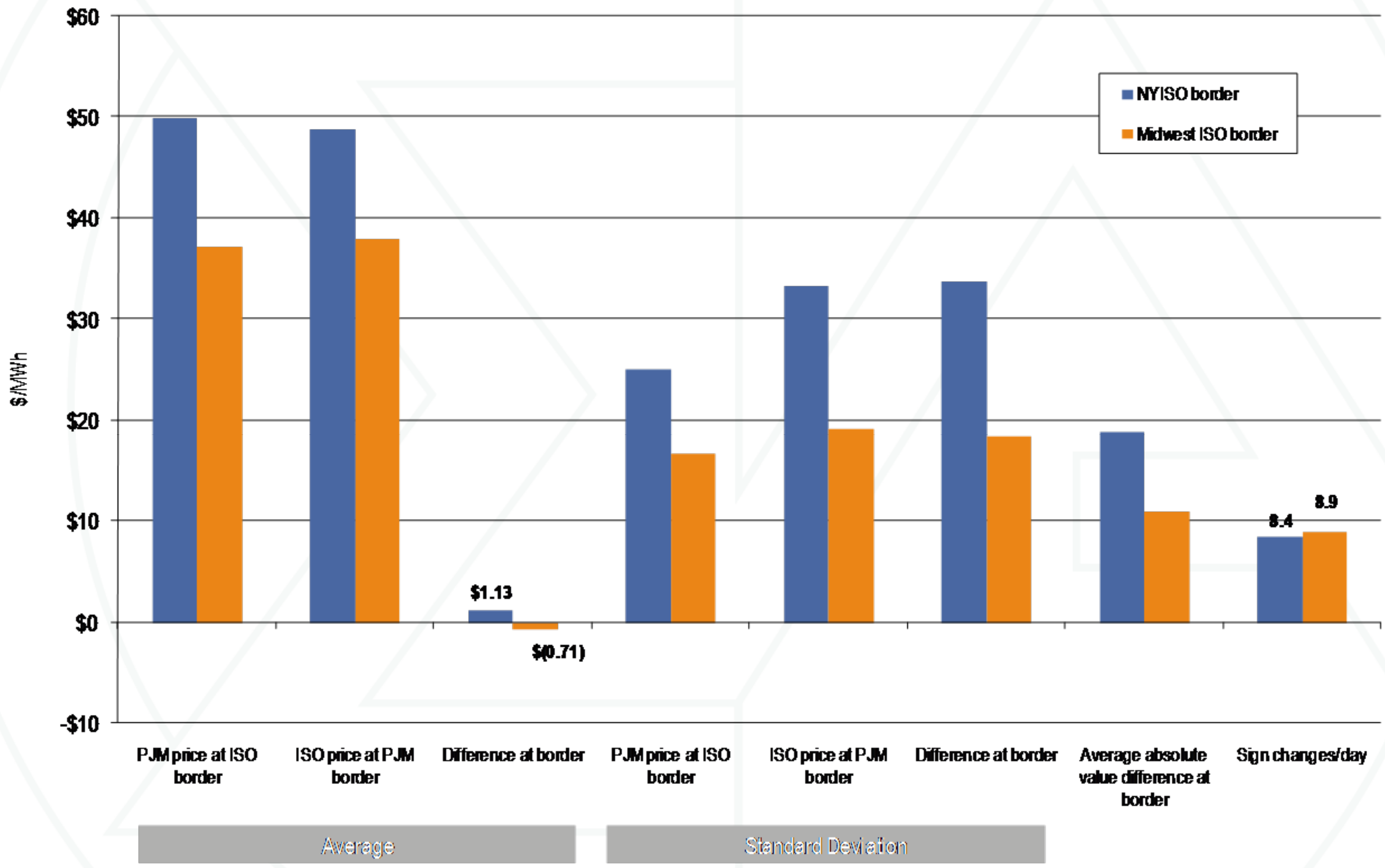

Table 4-12 Net scheduled and actual PJM interface flows (GWh): January through February 2010

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	1,677	53	1,624	3064%
CPLW	(318)	-	(318)	0%
DUK	(340)	312	(652)	(209%)
EKPC	(26)	(165)	139	(84%)
LGEE	235	176	59	34%
MEC	(739)	(875)	136	(16%)
MISO	(961)	542	(1,503)	(277%)
ALTE	(913)	(6)	(907)	15117%
ALTW	(440)	(40)	(400)	1000%
AMIL	257	(245)	502	(205%)
CIN	849	732	117	16%
CWLP	(9)	-	(9)	0%
FE	124	(387)	511	(132%)
IPL	593	20	573	2865%
MECS	(1,846)	508	(2,354)	(463%)
NIPS	(412)	(35)	(377)	1077%
WEC	836	(5)	841	(16820%)
NYISO	(1,614)	(2,354)	740	(31%)
LIND	(266)	(266)	-	0%
NEPT	(902)	(902)	-	0%
NYIS	(446)	(1,186)	740	(62%)
OVEC	1,275	2,120	(845)	(40%)
TVA	511	(160)	671	(419%)
Total	(300)	(351)	51	(14.5%)

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through February 2010

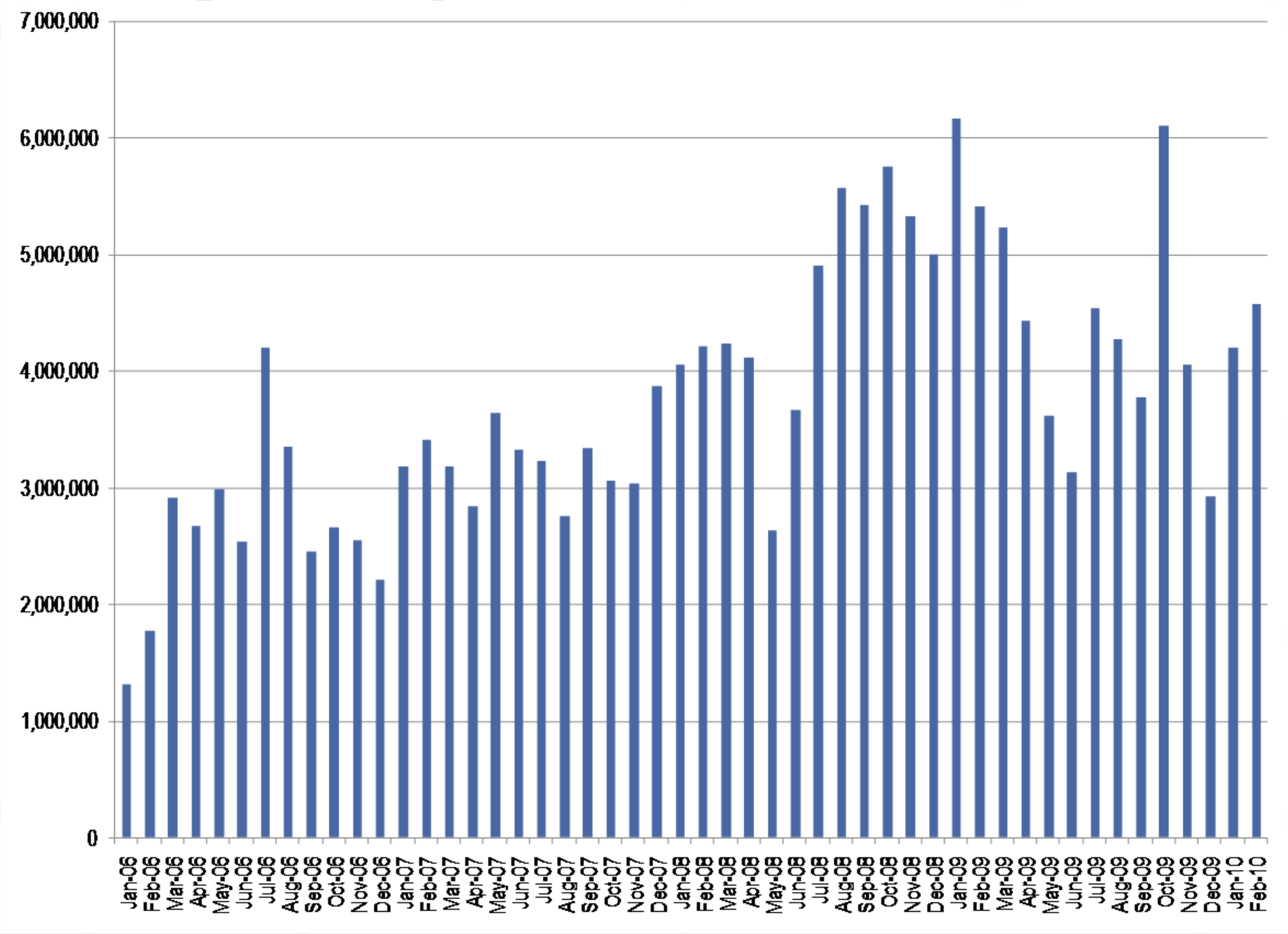

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: January 2009 through February 2010

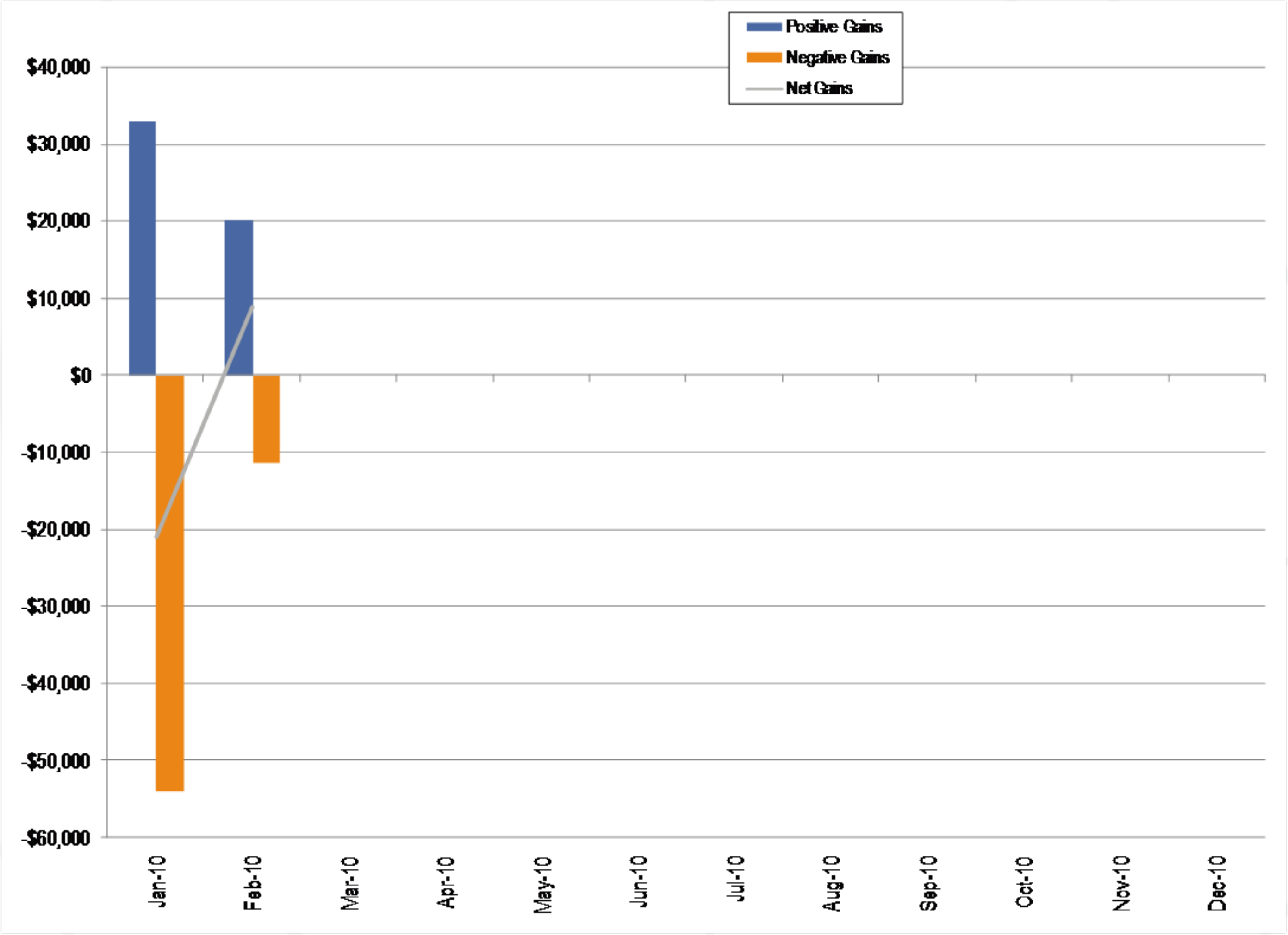

Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: January 2009 through February 2010

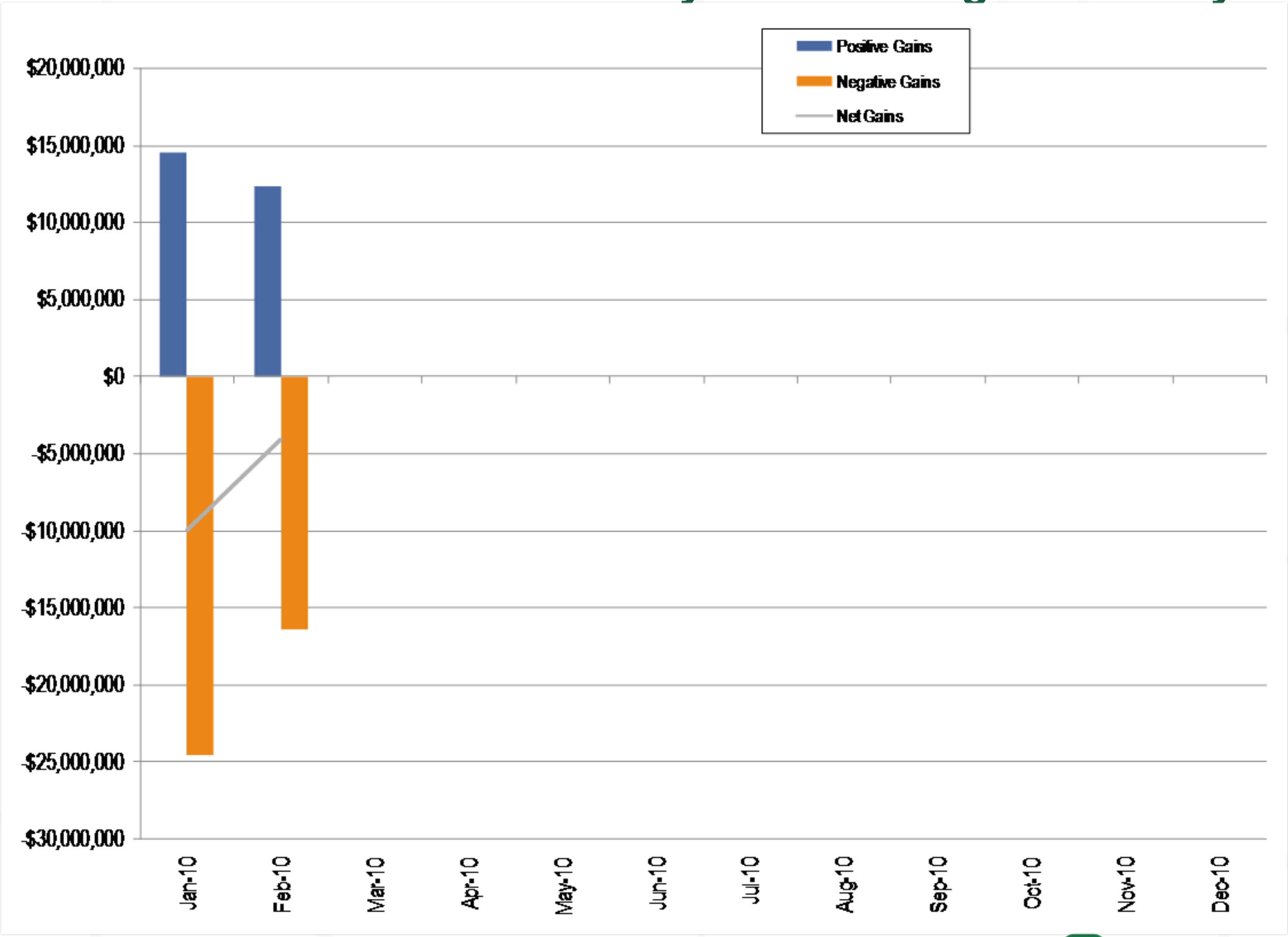

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through February 2010

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	**$54.35**	**$45.48**	**$49.09**	**$48.48**	**$5.26**	**($3.61)**	**$5.87**	**($3.01)**
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	**$35.97**	**$31.94**	**$33.37**	**$33.37**	**$2.61**	**($1.42)**	**$2.61**	**($1.42)**
2010	$50.09	$39.97	$44.20	$44.20	$5.89	($4.23)	$5.89	($4.23)

Figure 4-30 Spot import service utilization: January through February 2010

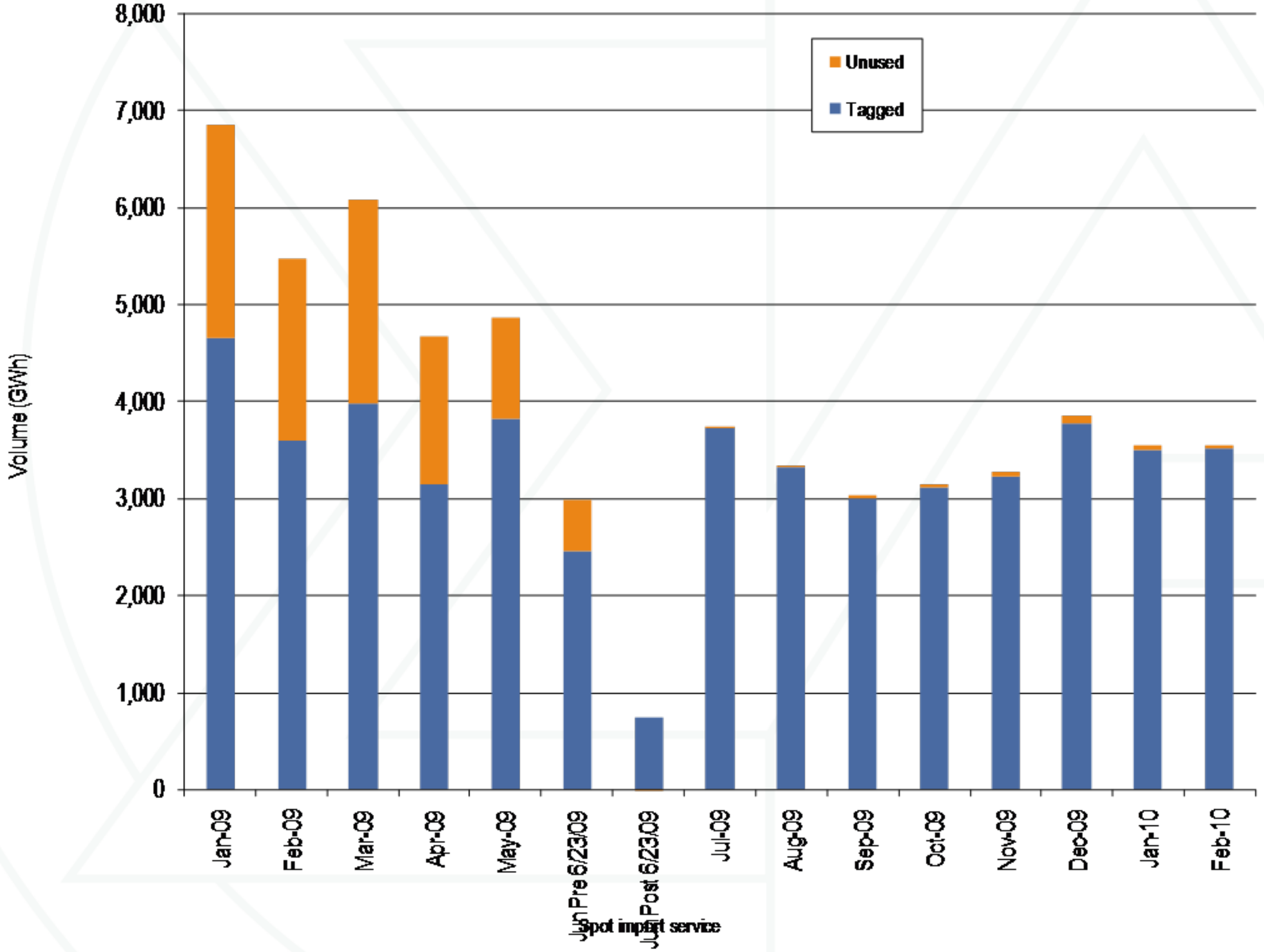

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through February 2010

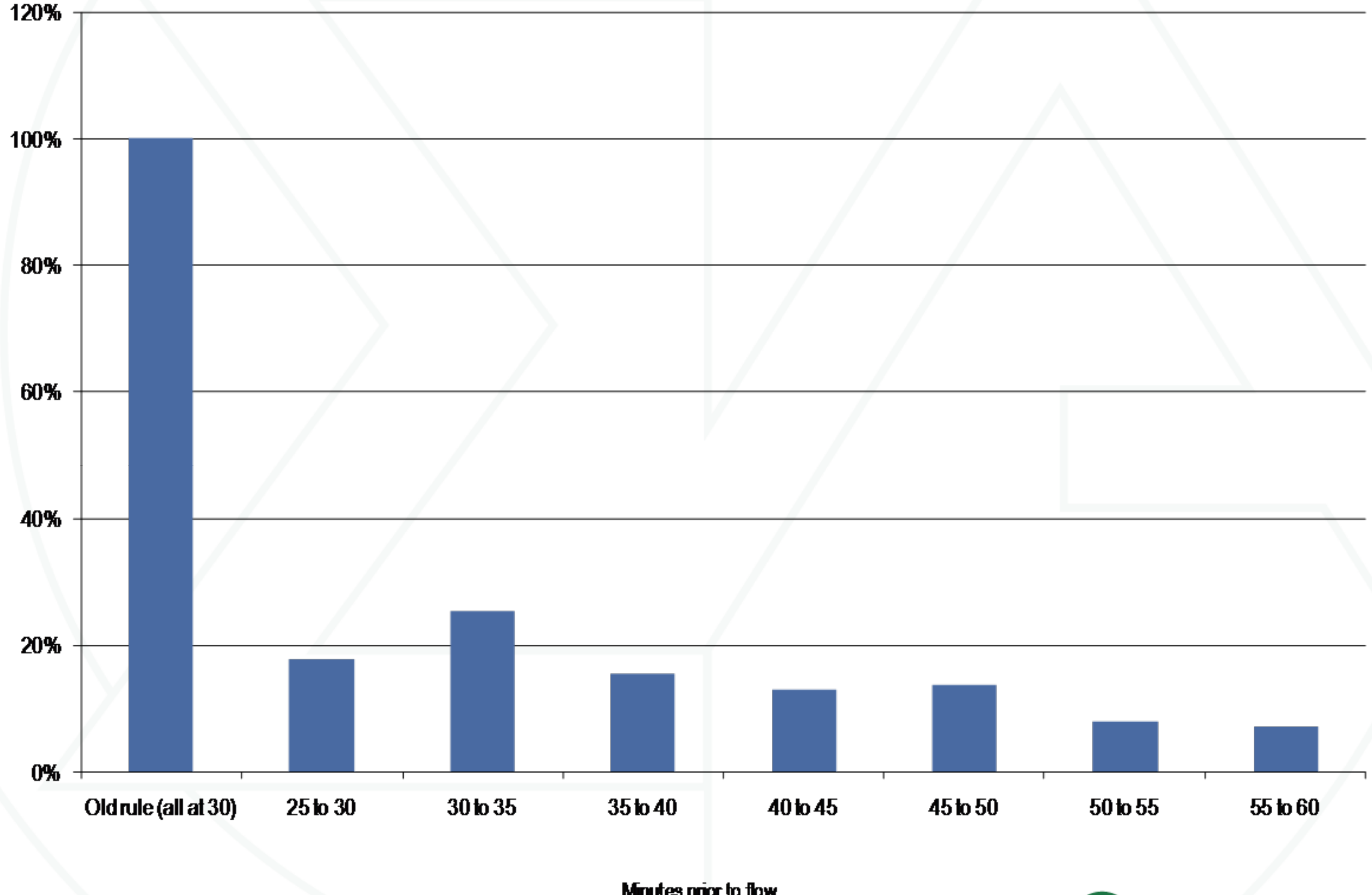

Table 5-5 PJM capacity summary (MW): June 1, 2007, through May 31, 2012

	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**					**$186.12**	
2010/2011 Third IA	$50.00						
2011/2012 BRA	**$110.00**						
2011/2012 First IA	$55.00						
2011/2012 ATSI FRR Integration Auction	**$108.89**						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00
2012/2013 ATSI FRR Integration Auction	**$20.46**						

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

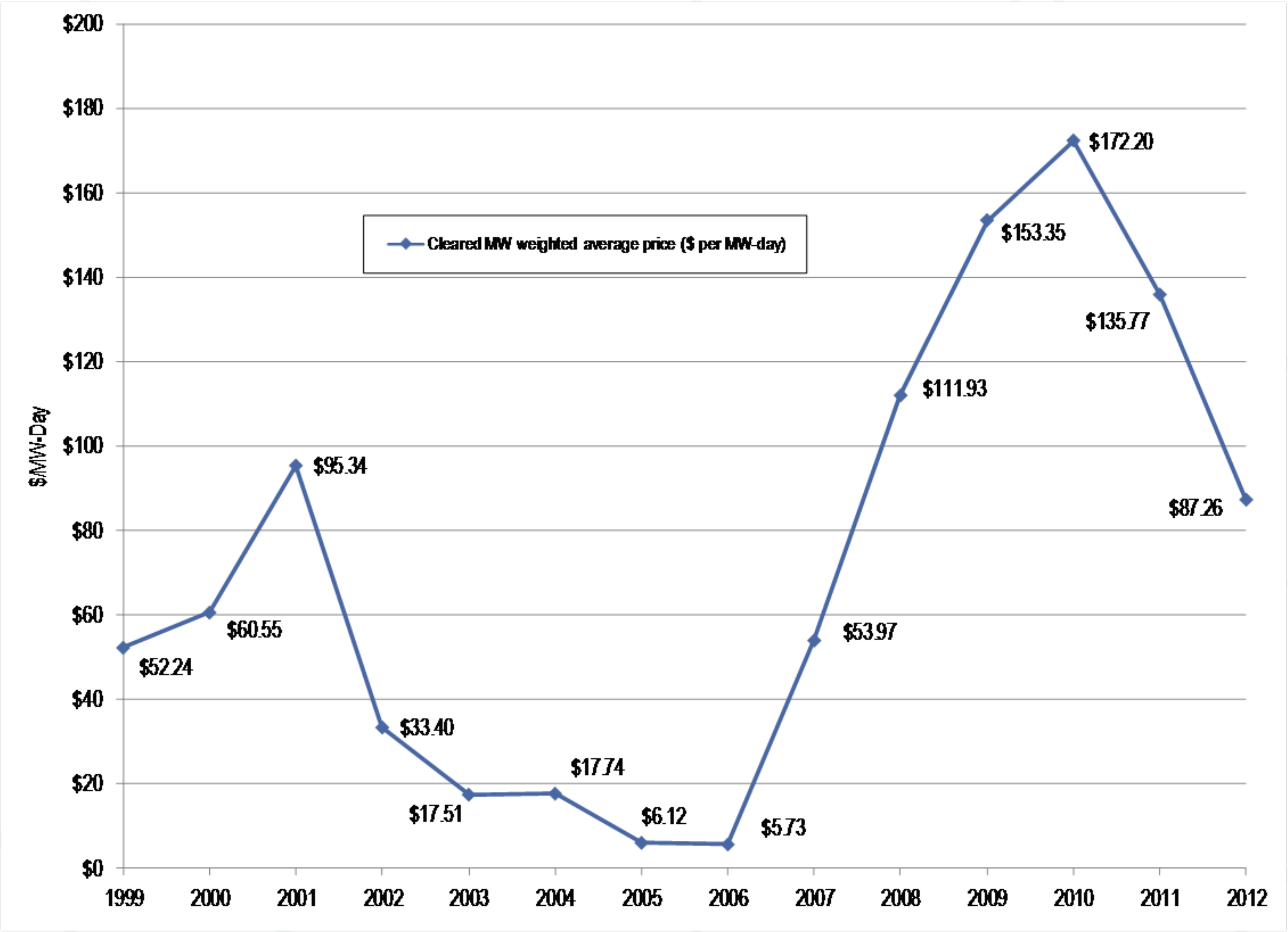

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2005 to February 2010

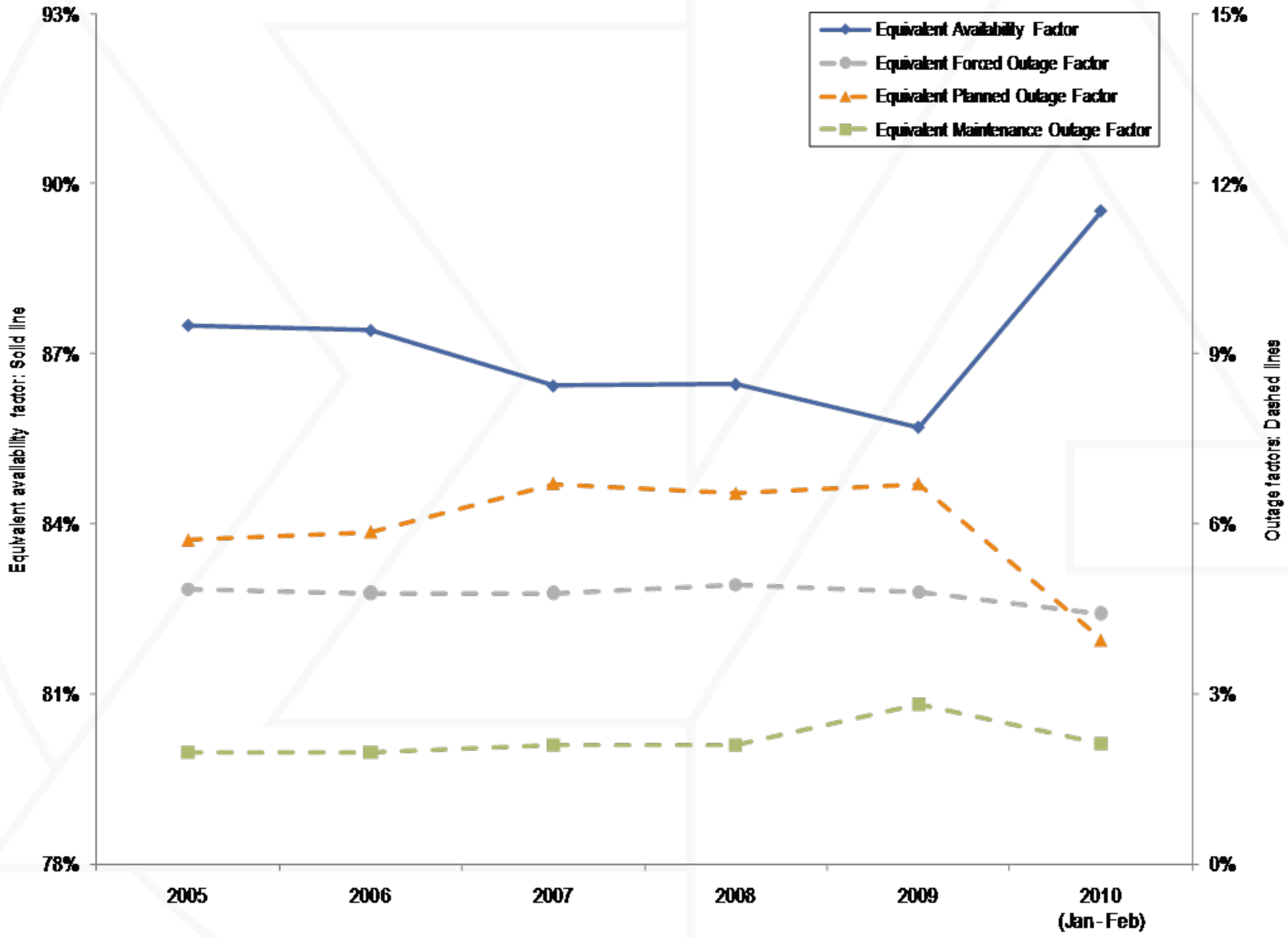

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to February 2010

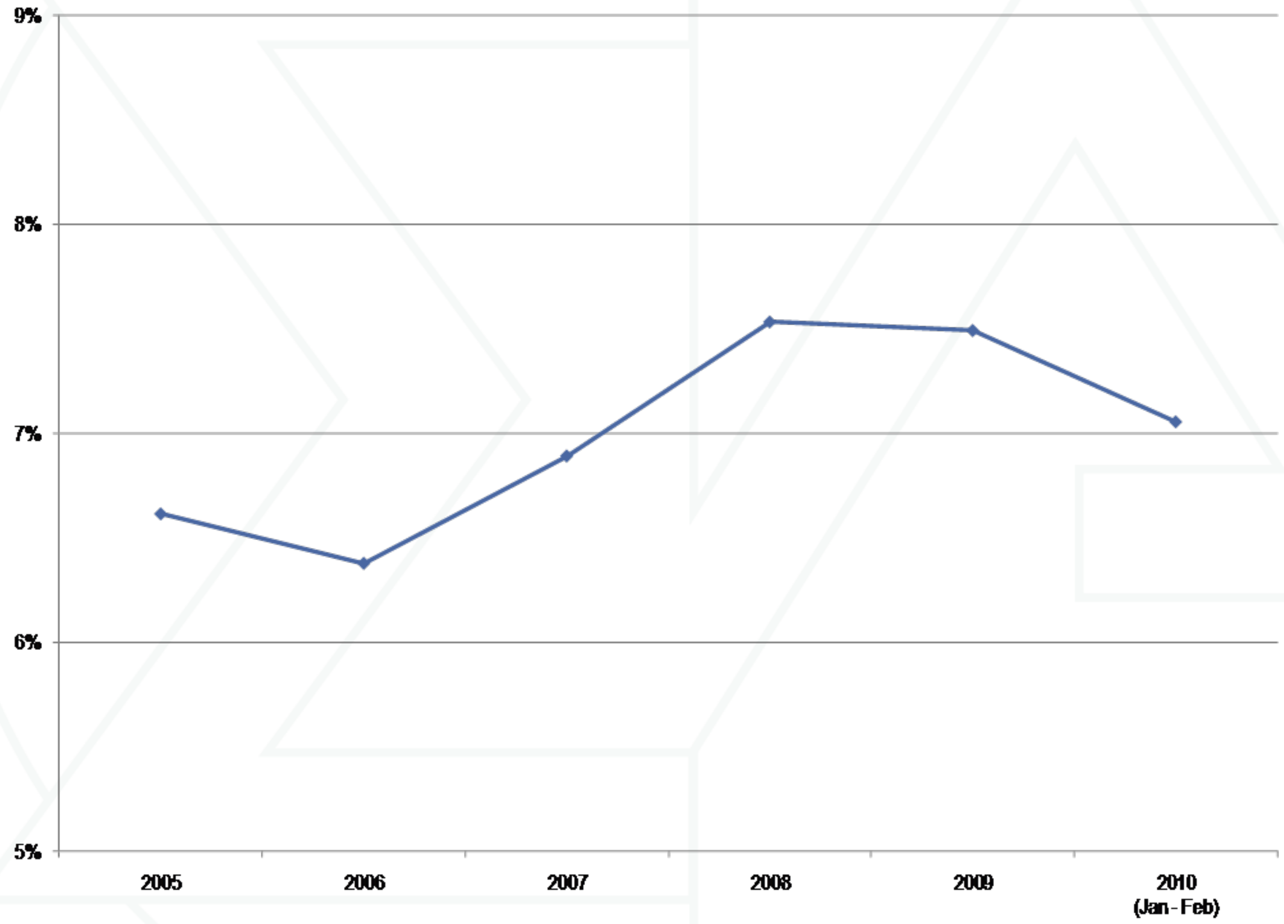

Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January-February 2010

	EFORd	XEFORd	EFORp
Combined Cycle	6.1%	6.1%	1.8%
Combustion Turbine	10.5%	8.1%	2.4%
Diesel	6.8%	4.8%	4.2%
Hydroelectric	0.9%	0.5%	0.5%
Nuclear	1.0%	1.0%	1.0%
Steam	9.1%	7.7%	6.0%
Total	7.1%	6.0%	3.8%

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2009 through February 2010

Year	Month	Percent of Hours With Three Pivotal Suppliers
2009	Jan	84%
2009	Feb	61%
2009	Mar	42%
2009	Apr	39%
2009	May	31%
2009	Jun	37%
2009	Jul	39%
2009	Aug	35%
2009	Sep	47%
2009	Oct	64%
2009	Nov	62%
2009	Dec	80%
2010	Jan	74%
2010	Feb	70%

Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2009 through February 2010

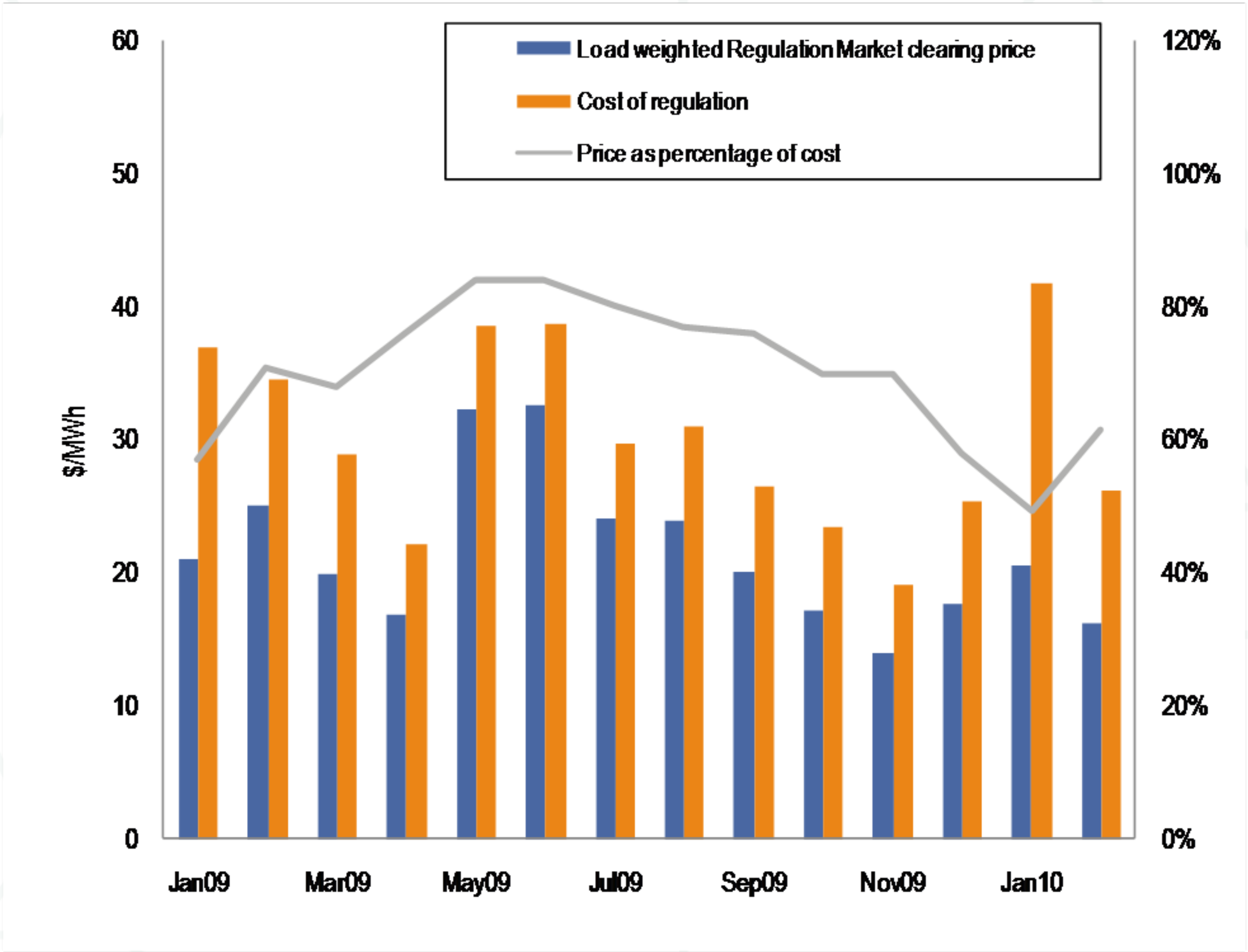

Table 6-9 Regulation Market pivotal supplier test results: January through February 2010, December 2008 through December 2009 and December 2007 through December 2008

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%
2010	Jan	74%	2009	Jan	84%
2010	Feb	70%	2009	Feb	61%

Table 6-10 Impact of $12 adder to cost based regulation offer: December 2008 through February 2010

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%
2010	Jan	$20.93	$17.16	$29,465,392	$2,641,053	9%
2010	Feb	$16.46	$13.38	$16,457,930	$1,844,846	11%
Total				$293,816,464	$10,675,305	3.6%

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule: December 2008 through February 2010

		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%
2010	Jan	950	$20.66	$29,479,645	$11.56	$23,065,981	$6,413,664	22%
2010	Feb	944	$16.17	$16,490,553	$9.93	$12,730,541	$3,760,012	23%
Total				$293,863,340		$236,225,831	$57,637,509	20%

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Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through February 2010

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%
2010	Jan	$64,990	$29,465,392	0%
2010	Feb	$66,223	$16,457,930	0%
Total		$2,428,561	$293,816,464	1%

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through February 2010

			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%	$1,565,825	15%	$166,112	2%	$2,001,220	19%
2009	Dec	$17,303,919	$600,585	3%	$329,864	2%	$104,496	1%	$1,034,945	6%
2010	Jan	$29,465,392	$2,641,053	9%	$6,413,664	22%	$64,990	0%	$9,119,707	31%
2010	Feb	$16,457,930	$1,844,846	11%	$3,942,974	24%	$66,223	0%	$5,854,043	36%
Total		$293,816,464	$10,675,305	3.6%	$57,920,471	20%	$2,428,561	1%	$71,024,337	25%

Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2009 through February 2010

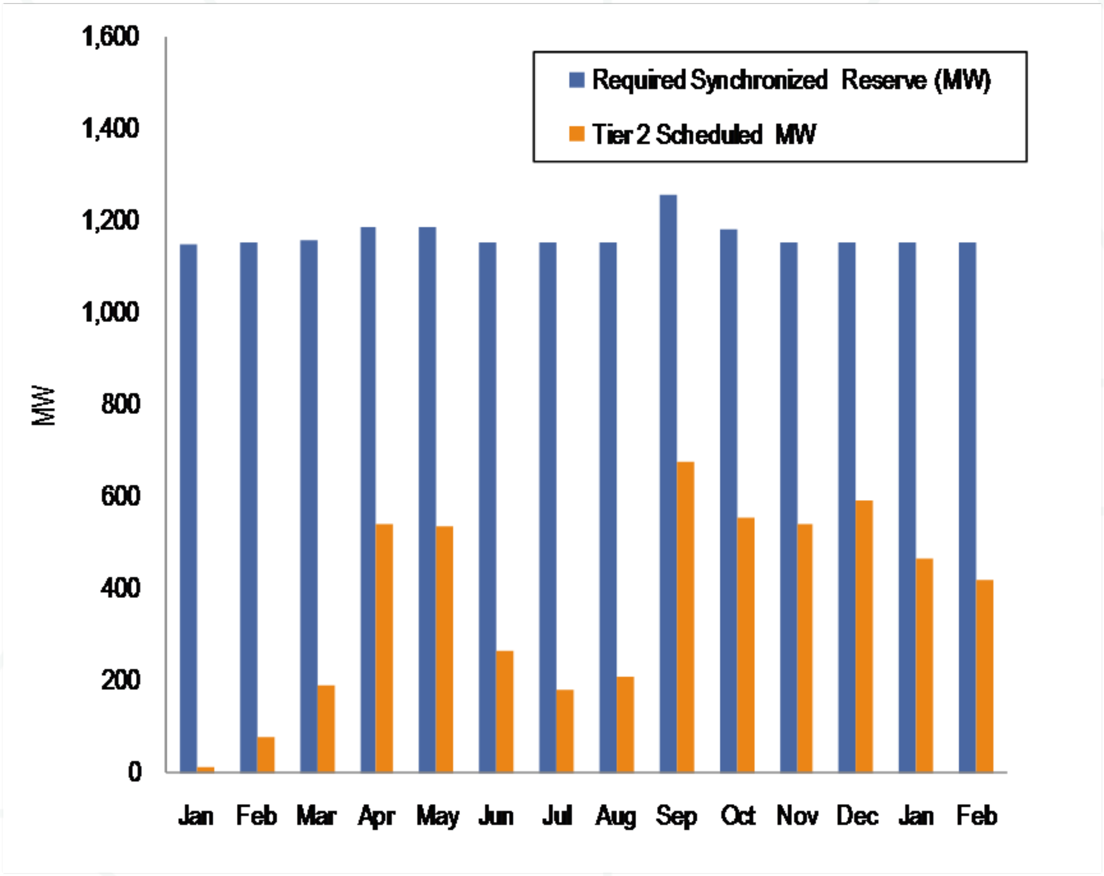

Table 6-16 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2009 through February 2010

Year	Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
2009	Jan	$1.24	$5.90	43%
2009	Feb	$2.01	$5.09	47%
2009	Mar	$1.98	$5.50	26%
2009	Apr	$2.49	$7.12	9%
2009	May	$1.91	$7.56	12%
2009	Jun	$1.76	$5.97	27%
2009	Jul	$1.95	$5.41	31%
2009	Aug	$1.36	$5.37	13%
2009	Sep	$1.77	$7.65	2%
2009	Oct	$1.37	$5.94	0%
2009	Nov	$0.50	$6.47	1%
2009	Dec	$1.05	$7.11	1%
2010	Jan	$2.03	$5.84	4%
2010	Feb	$0.10	$5.97	1%

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2009 through February 2010

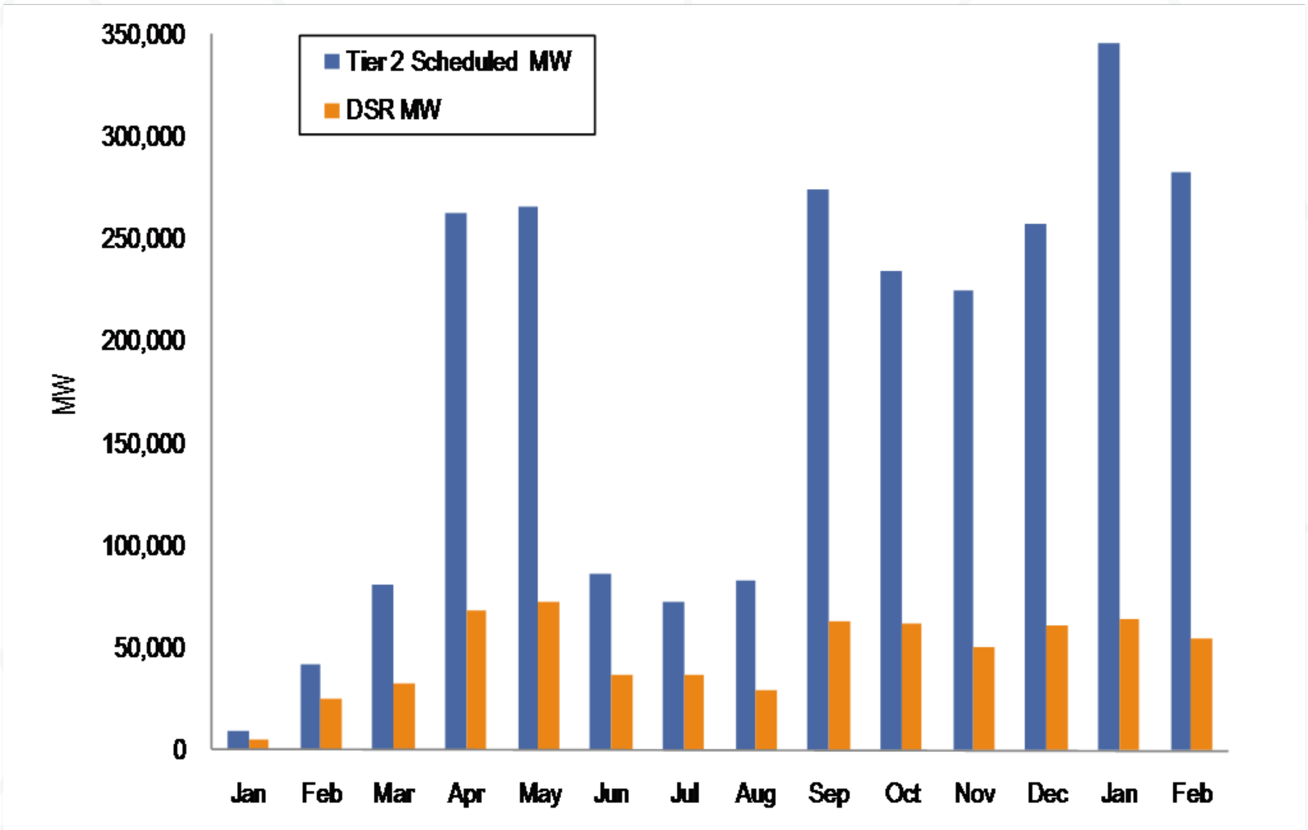

Table 6-17 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: Calendar year 2009 through February 2010

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Puchased	Total DASR Credits
2009	Jan	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
2009	Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
2009	Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
2009	Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
2009	May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
2009	Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578
2009	Jul	6,071	$0.00	$0.50	$0.04	4,191,307	$155,790
2009	Aug	6,725	$0.00	$4.00	$0.13	4,773,330	$620,430
2009	Sep	5,438	$0.00	$0.42	$0.02	3,764,923	$77,945
2009	Oct	5,023	$0.00	$0.42	$0.03	3,610,812	$102,984
2009	Nov	5,188	$0.00	$0.42	$0.03	3,556,557	$113,027
2009	Dec	5,992	$0.00	$0.50	$0.05	3,921,732	$191,599
2010	Jan	6,246	$0.00	$0.75	$0.05	4,647,334	$119,451
2010	Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$171,919

Table 6-18 Black Start yearly zonal charges for network transmission use: January through February 2010

Zone	Network Charges
AECO	$61,906
AEP	$122,623
AP	$22,682
BGE	$80,357
ComEd	$617,147
DAY	$24,378
DLCO	$4,448
DPL	$65,085
JCPL	$72,793
Met-Ed	$67,681
PECO	$121,059
PENELEC	$56,403
Pepco	$37,190
PPL	$25,818
PSEG	$157,926

Table 7-1 Total monthly PJM congestion (Dollars (Millions)): Calendar years 2008 through February 2010

	2008	2009	2010
Jan	$231.0	$149.3	$218.5
Feb	$168.1	$83.0	$106.4
Mar	$86.4	$74.6	
Apr	$126.2	$25.6	
May	$182.8	$25.9	
Jun	$436.4	$49.8	
Jul	$359.8	$39.4	
Aug	$127.4	$72.1	
Sep	$124.8	$23.9	
Oct	$102.2	$42.7	
Nov	$93.0	$36.3	
Dec	$78.4	$96.4	
Total	$2,116.6	$719.0	$324.9

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 February 28, 2009

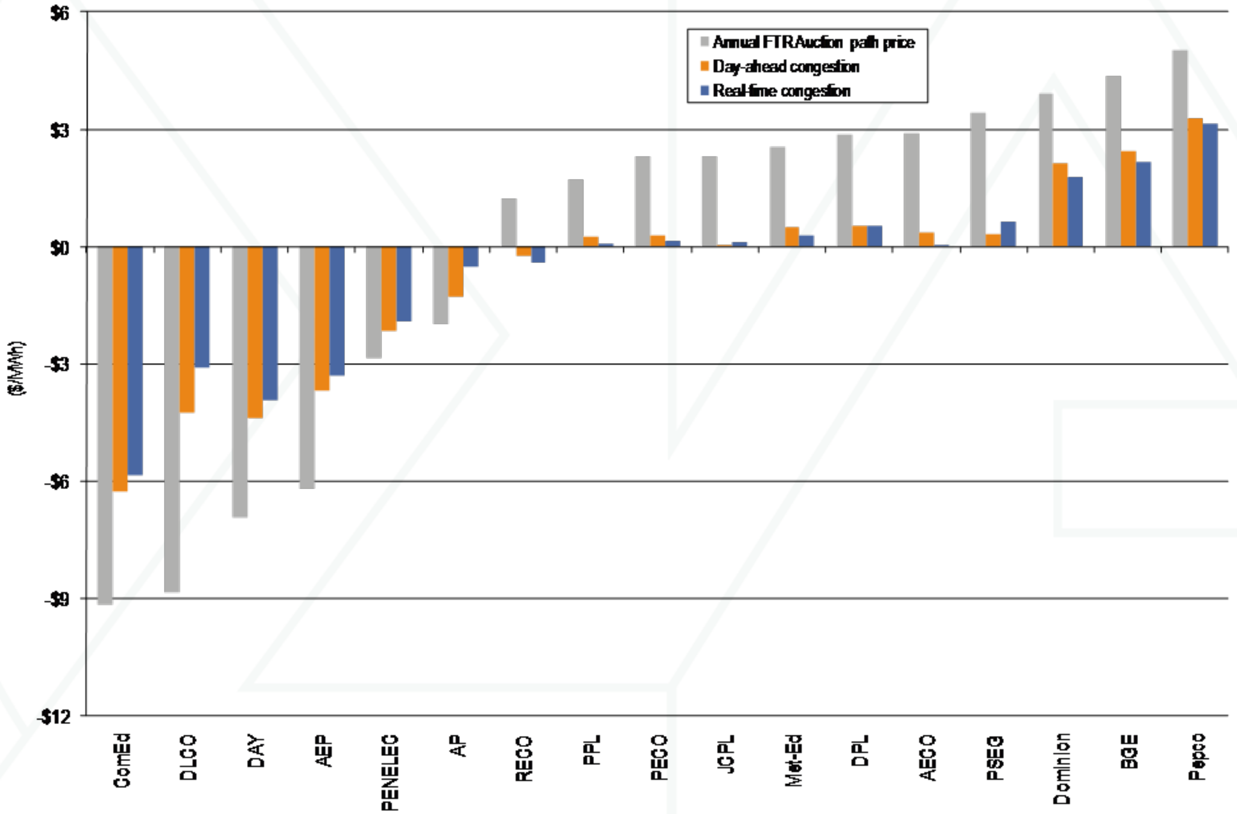

Table 8-25 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2009 to 2010, through February 2010

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$16,334,077	$480,693	$16,814,770	$13,872,643	$2,942,127	>100%
AEP	$4,284,698	$132,990,866	$137,275,564	$108,208,573	$29,066,991	>100%
AP	$45,451,856	$150,887,438	$196,339,294	$30,859,156	$165,480,139	>100%
BGE	$46,459,694	$2,399,536	$48,859,230	$8,029,590	$40,829,640	>100%
ComEd	$14,549,758	$25,974,326	$40,524,084	$51,462,124	($10,938,041)	78.7%
DAY	$6,207,117	$668,080	$6,875,197	$8,658,186	($1,782,989)	79.4%
DLCO	$2,450,918	$2,619	$2,453,537	$14,977,647	($12,524,111)	16.4%
Dominion	$16,378,604	$577,204	$16,955,808	$57,926,881	($40,971,073)	29.3%
DPL	$6,134,065	$129,260,214	$135,394,279	$23,056,206	$112,338,073	>100%
JCPL	$28,119,187	$740,087	$28,859,274	$17,281,463	$11,577,811	>100%
Met-Ed	$108,900	$10,188,146	$10,297,046	$16,364,248	($6,067,202)	62.9%
PECO	$1,932,121	$15,543,473	$17,475,594	($16,737,899)	$34,213,493	>100%
PENELEC	$22,966,832	$9,924,075	$32,890,907	$5,767,089	$27,123,818	>100%
Pepco	$21,798,040	$1,480,509	$23,278,549	$115,182,267	($91,903,718)	20.2%
PJM	$7,727,385	($36,688)	$7,690,697	$2,247,094	$5,443,602	>100%
PPL	$1,102,352	$13,053,989	$14,156,341	($20,168,756)	$34,325,097	>100%
PSEG	$83,906,643	$2,591,340	$86,497,983	$4,165,974	$82,332,009	>100%
RECO	($41,455)	$0	($41,455)	$943,165	($984,620)	0%
Total	$325,870,792	$496,725,907	$822,596,699	$442,095,652	$380,501,047	>100%

Table 8-27 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010, through February 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,332	$2,860,960	$24,509,727	($2,395,435)	$9,829,974	($12,225,409)	<0%
AEP	$223,262,229	$144,145,273	$218,757,797	$148,649,705	$97,526,724	$51,122,981	>100%
AP	$365,048,488	$150,349,533	$329,655,454	$185,742,567	$106,700,980	$79,041,587	>100%
BGE	$52,131,739	$26,531,954	$35,122,134	$43,541,559	$33,351,573	$10,189,986	>100%
ComEd	$27,261,279	$48,393,172	$15,077,982	$60,576,469	$158,840,629	($98,264,160)	38.1%
DAY	$7,505,314	$826,990	$69,456	$8,262,848	$6,745,359	$1,517,489	>100%
DLCO	$2,454,337	$6,999,240	($2,724,555)	$12,178,132	$19,013,117	($6,834,985)	64.1%
Dominion	$213,840,239	$137,694,844	$233,593,748	$117,941,335	$129,854,757	($11,913,422)	90.8%
DPL	$17,792,090	$10,292,129	$34,855,729	($6,771,510)	$23,393,245	($30,164,755)	<0%
JCPL	$34,924,213	$1,917,315	$43,217,780	($6,376,252)	$15,734,380	($22,110,632)	<0%
Met-Ed	$27,312,021	$13,382,569	$33,153,125	$7,541,465	$4,496,367	$3,045,098	>100%
PECO	$49,863,646	$18,495,883	$55,655,197	$12,704,332	($18,830,320)	$31,534,652	>100%
PENELEC	$49,412,326	$40,604,799	$69,719,682	$20,297,443	$50,230,087	($29,932,644)	40.4%
Pepco	$23,702,306	$86,443,177	$89,706,022	$20,439,461	$53,215,527	($32,776,066)	38.4%
PJM	$9,979,482	($4,439,263)	($4,061,052)	$9,601,271	$6,383,137	$3,218,134	>100%
PPL	$55,143,860	$19,907,744	$61,136,450	$13,915,154	($8,559,896)	$22,475,050	>100%
PSEG	$94,609,238	$18,416,441	$110,995,134	$2,030,545	($3,498,696)	$5,529,241	>100%
RECO	($41,455)	($786,321)	($2,759,139)	$1,931,363	$1,104,920	$826,443	>100%
Total	$1,273,454,684	$722,036,440	$1,345,680,671	$649,810,453	$685,531,864	($35,721,411)	94.8%

Table 8-28 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010, through February 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*	**$954,918,288**	**$722,052,208**	**$1,021,266,943**	**$655,703,554**	**$685,531,865**	**($29,828,311)**	**95.6%**

* Shows nine months ended 28-Feb-10