2009 Quarterly State of the PJM Market: January through September

Members Committee

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Monitoring Analytics

Table 1-1 Total price per MWh: January through September 2009 (New Table)

Category	$/MWh	Percent
Load Weighted Energy	$39.57	73.4%
Capacity	$9.03	16.8%
Transmission Service	$3.54	6.6%
Operating Reserves (Uplift)	$0.44	0.8%
Regulation	$0.33	0.6%
Reactive	$0.32	0.6%
PJM Administrative	$0.31	0.6%
Transmission Cost Recovery	$0.18	0.3%
Transmission Owner (Schedule 1A)	$0.08	0.1%
Synchronized Reserves	$0.03	0.1%
Black Start Services	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
NERC/RFC	$0.01	0.0%
Load Response	$0.00	0.0%
Total	$53.87	100.0%

Figure 2-1 Average PJM aggregate supply curves: July through September 2008 and 2009 (See 2008 SOM, Figure 2-1)

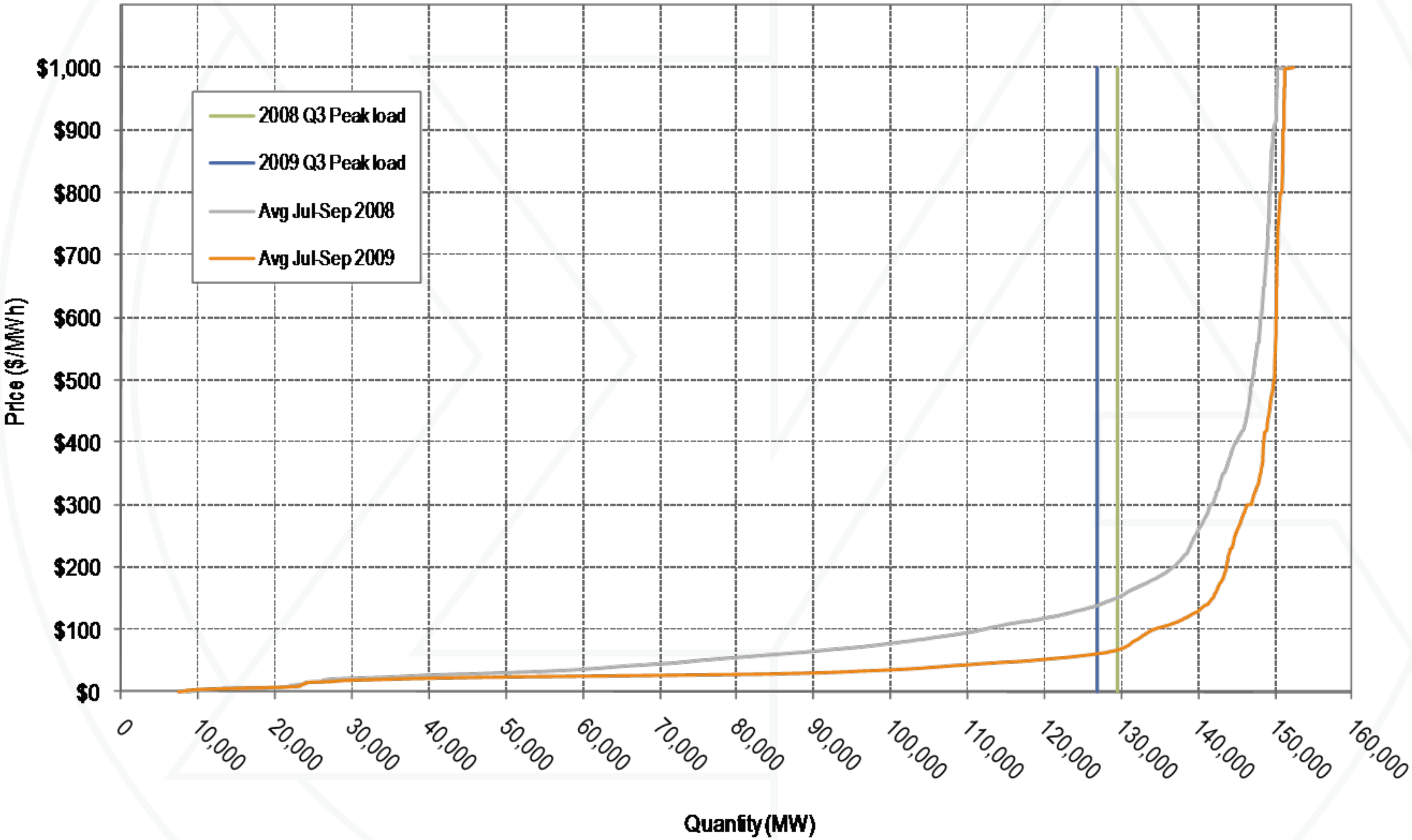

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Table 2-1 Actual PJM footprint quarter three peak loads: 2005 to 2009 (See 2008 SOM, Table 2-2)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
2005	26-Jul-05	1600	133,761	NA
2006	02-Aug-06	1700	144,644	10,883
2007	08-Aug-07	1600	139,428	(5,216)
2008	17-Jul-08	1700	129,481	(9,947)
2009	10-Aug-09	1700	126,805	(2,676)

Table 2-32 Type of fuel used (By real-time marginal units): January through September 2009 (See 2007 SOM, Table 2-32)

Fuel Type	Percent on the Margin
Coal	73%
Natural Gas	20%
Petroleum	5%
Landfill Gas	1%
Interface	1%
Misc	0%

Table 2-34 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2009 (New Table)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($3.04)	82.9%
Gas	CC	($0.68)	18.6%
Gas	CT	$0.02	(0.5%)
Gas	Diesel	$0.00	(0.1%)
Gas	Steam	$0.01	(0.3%)
Interface	Interface	($0.00)	0.0%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	($0.02)	0.5%
Oil	CC	($0.00)	0.0%
Oil	CT	$0.04	(1.1%)
Oil	Diesel	($0.02)	0.4%
Oil	Steam	$0.02	(0.5%)
Uranium	Steam	($0.00)	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.00	(0.0%)
Total		($3.67)	100.0%

Table 2-37 Average real-time markup component (By price category): January through September 2009 (See 2008 SOM, Table 2-41)

	Average Markup Component	Frequency
Below $20	($0.29)	5.1%
$20 to $40	($5.49)	73.7%
$40 to $60	($3.44)	23.6%
$60 to $80	$0.72	5.7%
$80 to $100	$9.01	2.3%
$100 to $120	$0.76	0.7%
$120 to $140	$40.38	0.4%
$140 to $160	$13.87	0.2%
Above $160	$52.56	0.2%

Table 2-46 PJM real-time average load: Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-44)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	30,113	30,170	5,529	NA	NA	NA
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	**76,956**	**76,355**	**13,879**	**(3.2%)**	**(2.7%)**	**0.9%**

Figure 2-6 PJM real-time average load: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-5)

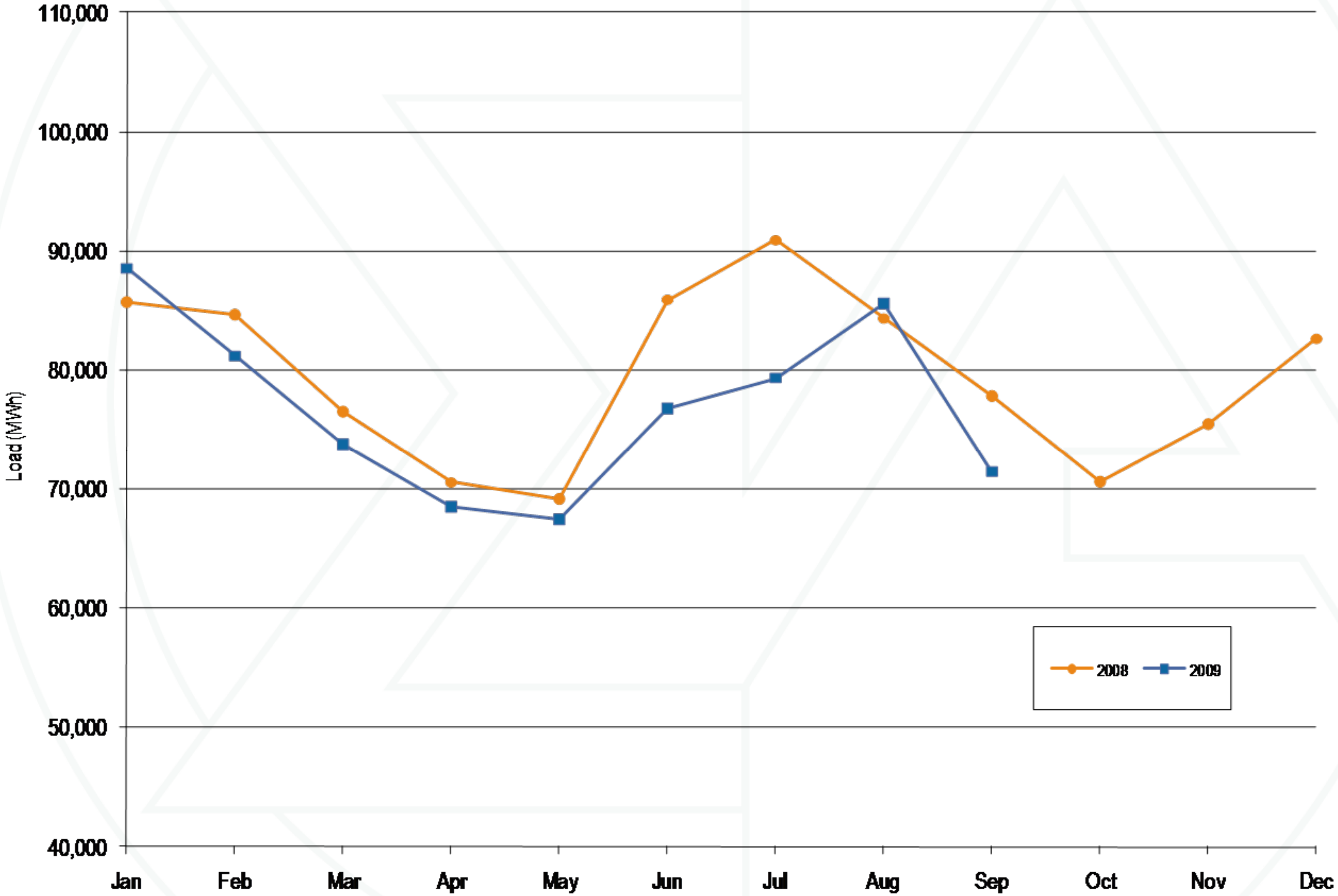

Table 2-49 Cleared day-ahead and real-time load (MWh): January through September 2009 (See 2008 SOM, Table 2-47)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	72,973	1,603	15,104	89,680	76,956	12,724	(2,380)
Median	72,358	1,609	15,369	89,515	76,355	13,160	(2,209)
Standard deviation	13,129	458	2,660	15,756	13,879	1,877	(783)

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-8)

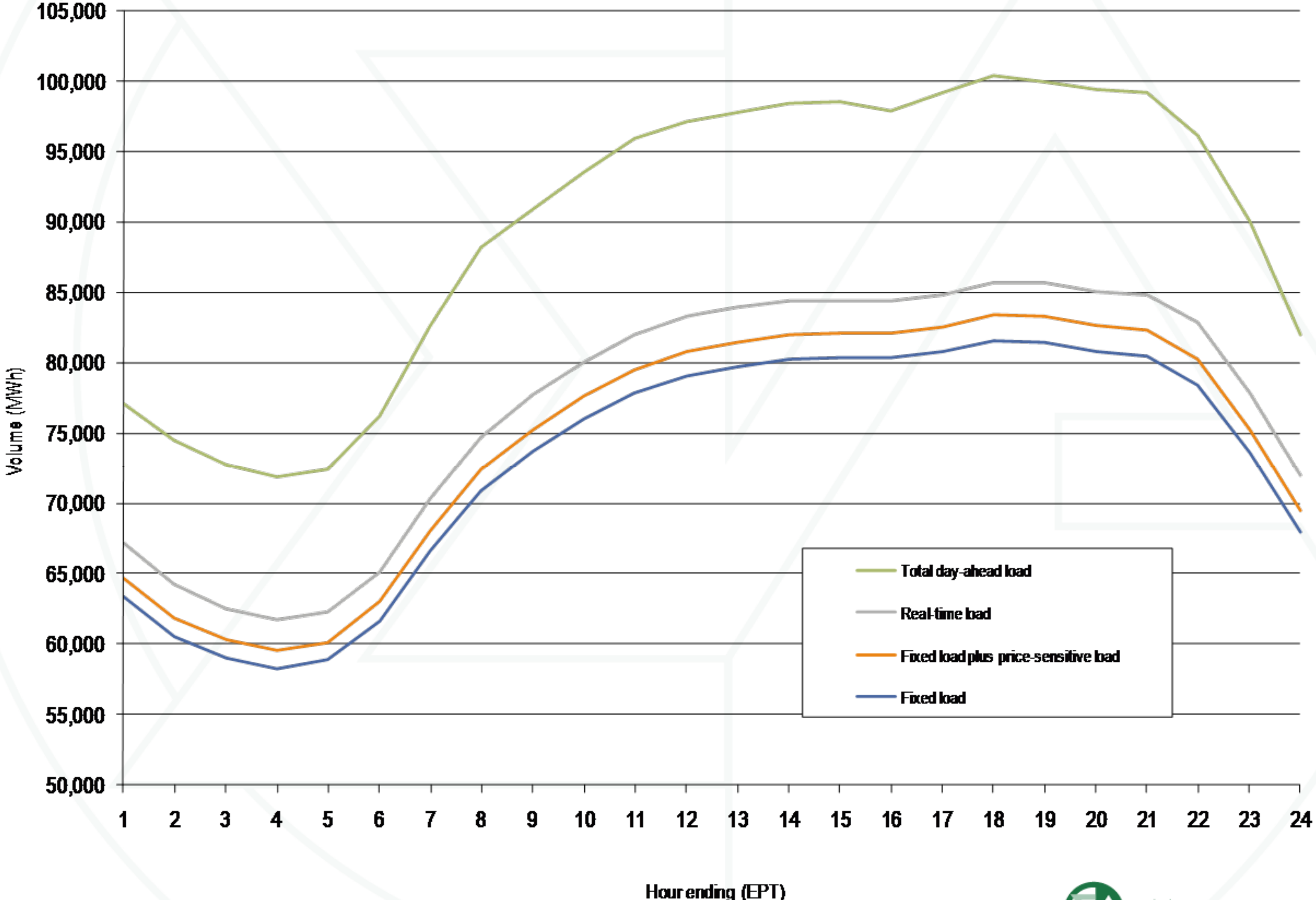

Table 2-50 Day-ahead and real-time generation (MWh): January through September 2009 (See 2008 SOM, Table 2-48)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Generation Plus INC Offer
Average	79,502	12,684	92,186	78,850	652	13,336
Median	79,455	12,553	92,109	78,316	**1,139**	**13,793**
Standard deviation	15,458	1,615	16,220	14,242	1,216	1,978

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): January through September 2009 (See 2008 SOM, Figure 2-9)

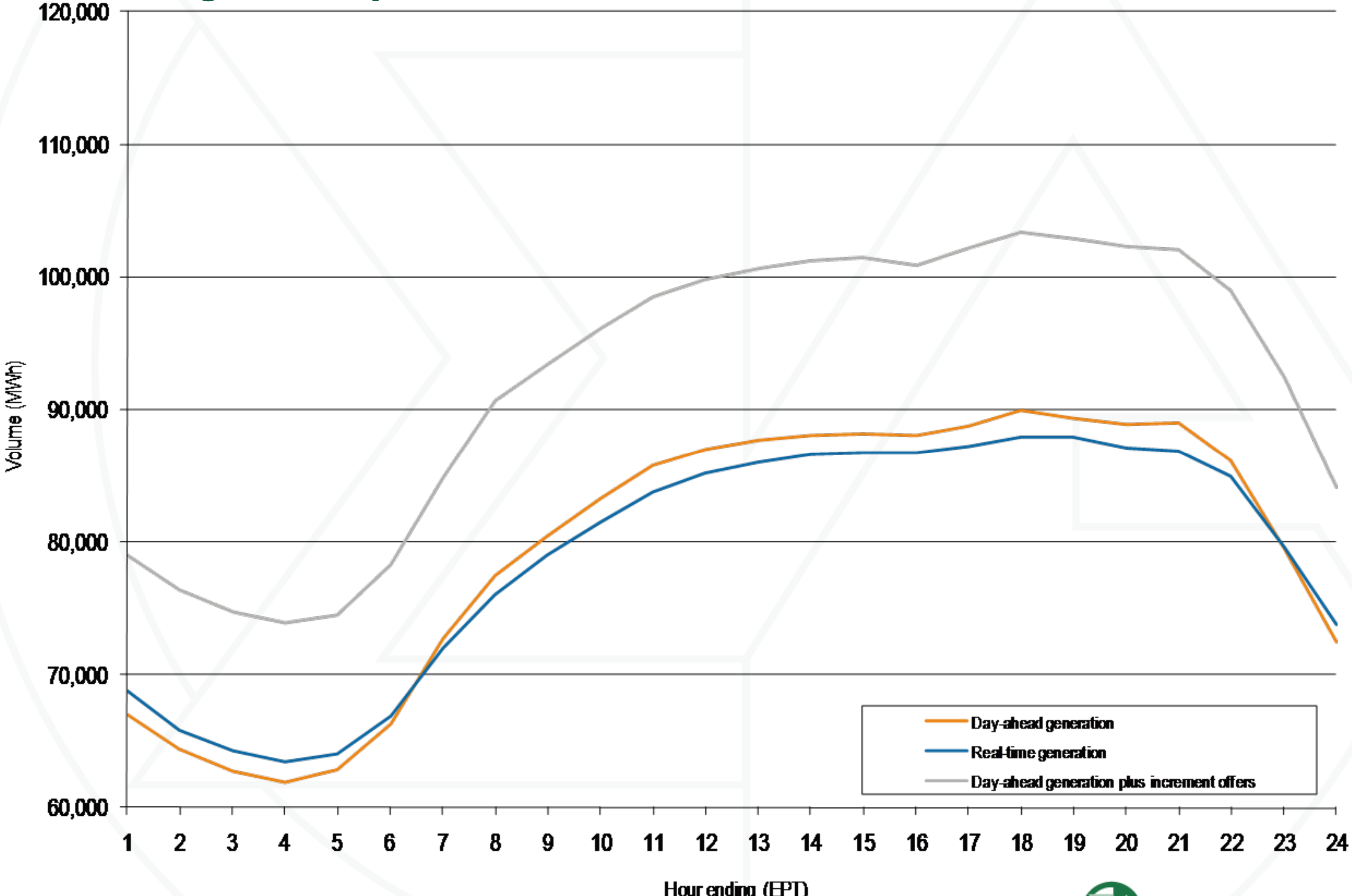

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Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-10)

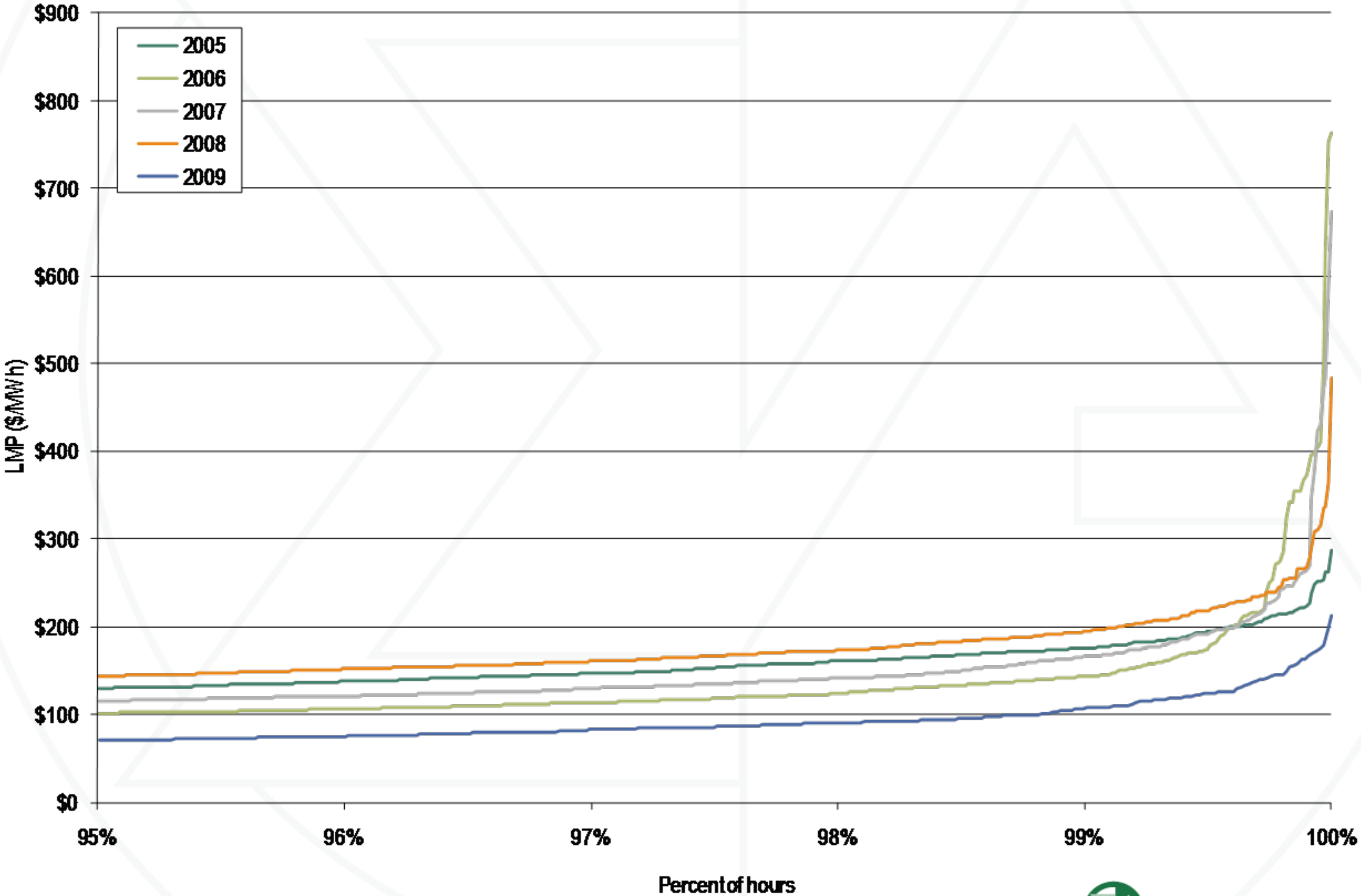

Table 2-55 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-53)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.72	$20.51	$28.38	NA	NA	NA
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	**$39.57**	**$34.57**	**$19.04**	(44.4%)	(41.9%)	(53.5%)

Figure 2-12 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through September 2009 (See 2008 SOM, Figure 2-11)

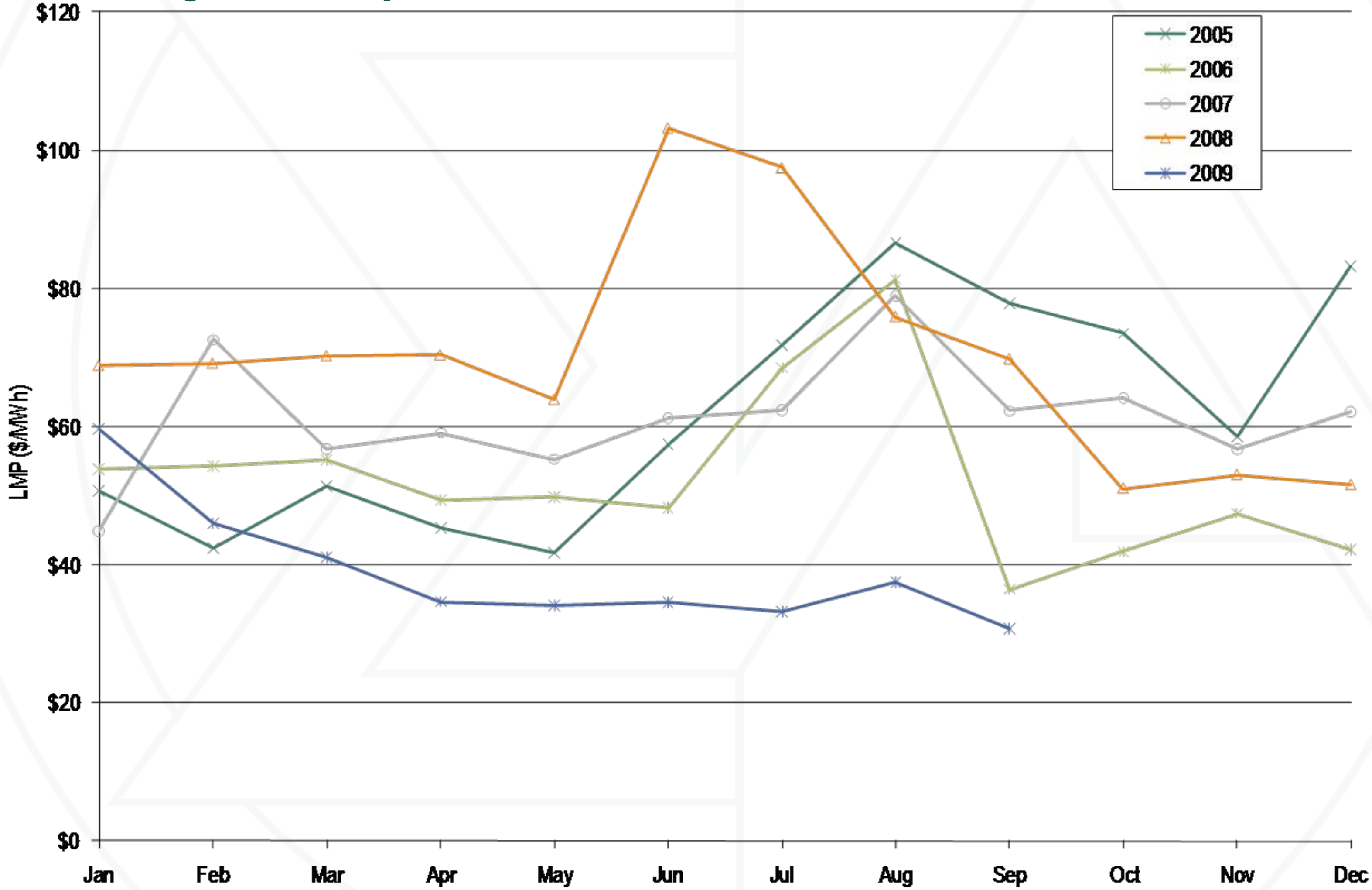

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Figure 2-13 Spot average fuel price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-12)

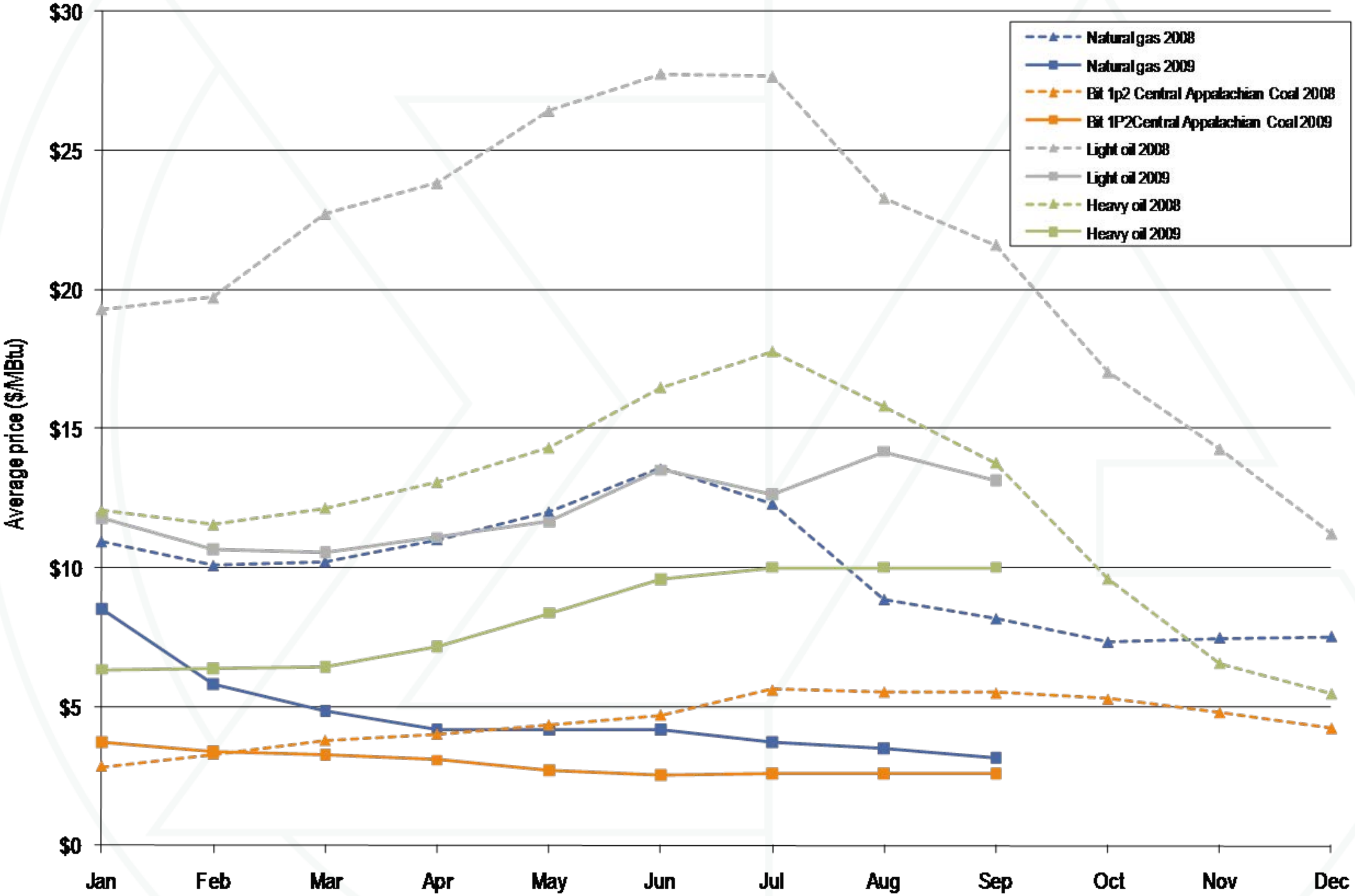

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Figure 2-14 Spot average emission price comparison: Calendar years 2008 through September 2009 (See 2008 SOM, Figure 2-13)

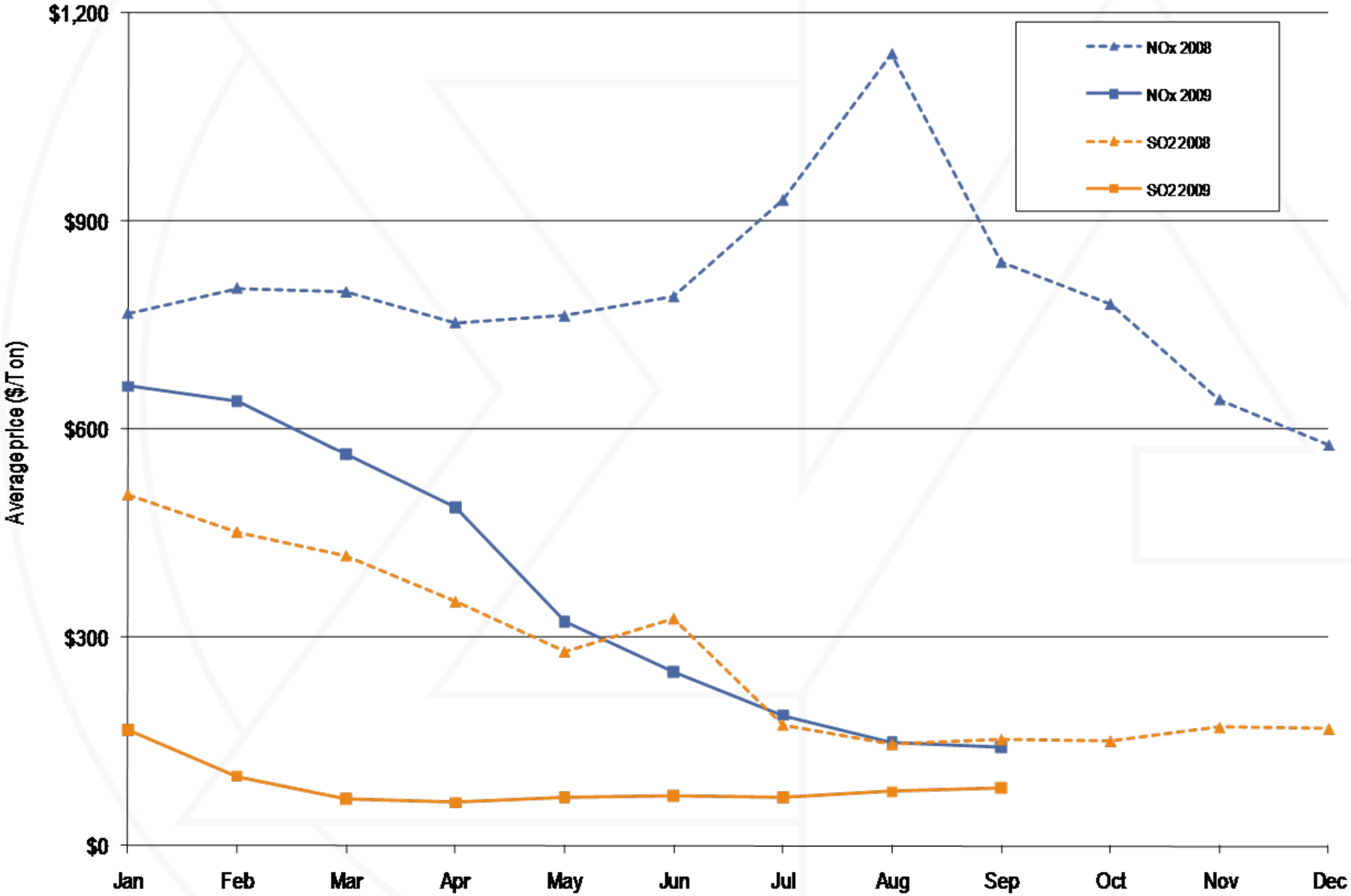

Table 2-58 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through September 2009, year-over-year method

	2008 (Jan - Sep) Load-Weighted LMP	2009 (Jan - Sep) Fuel-Cost-Adjusted, Load-Weighed LMP	Change
Average	$77.27	$68.61	(11.2%)

Table 2-59 Components of PJM annual, load-weighted, average LMP: January through September 2009 (See 2008 SOM, Table 2-57)

Element	Contribution to LMP	Percent
Coal	$22.06	55.8%
Gas	$12.10	30.6%
Oil	$3.26	8.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.02	0.0%
FMU Adder	$0.19	0.5%
SO2	$1.33	3.4%
NOX	$0.49	1.2%
VOM	$4.40	11.1%
Markup	($3.67)	(9.3%)
Offline CT Adder	$0.05	0.1%
UDS Override Differential	($0.38)	(1.0%)
Dispatch Differential	($0.21)	(0.5%)
M2M Adder	($0.18)	(0.5%)
Flow violation Adjustment	($0.01)	(0.0%)
Unit LMP Differential	($0.00)	(0.0%)
NA	$0.12	0.3%
LMP	$39.56	100.0%

Table 2-78 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through September 2009 (See 2008 SOM, Table 2-78)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$37.35	$37.42	$0.08	0.2%
Median	$35.29	$33.00	**($2.29)**	**(7.0%)**
Standard deviation	$14.32	$17.92	$3.60	20.1%

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through September 2009 (See 2008 SOM, Table 2-79)

Year	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	**$37.35**	**$37.42**	**$0.08**	**0.2%**

Figure 2-18 Hourly real-time minus hourly day-ahead LMP: January through September 2009 (See 2008 SOM, Figure 2-17)

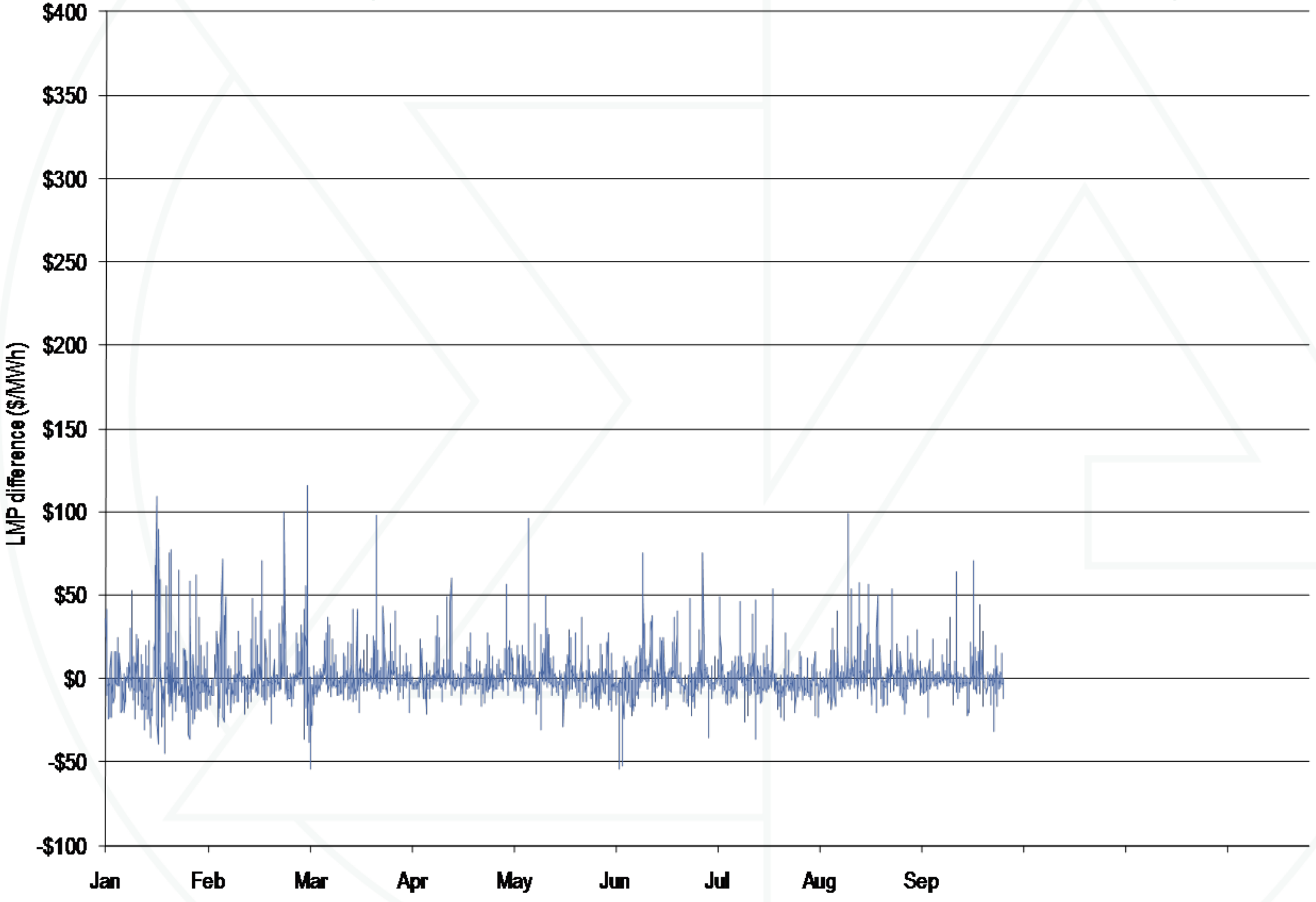

Figure 2-20 PJM system hourly average LMP: January through September 2009 (See 2008 SOM, Figure 2-19)

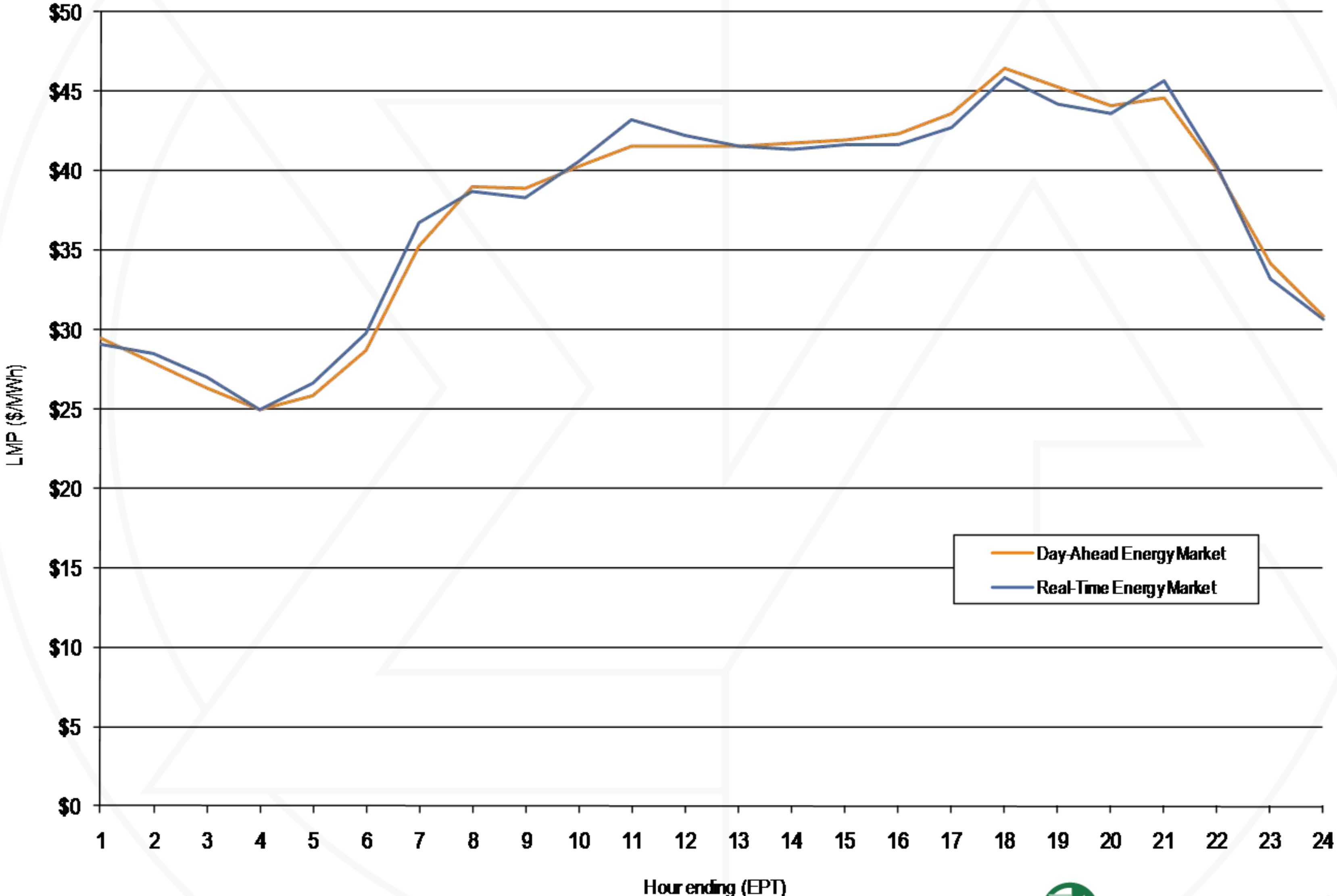

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-83)

	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%						
Nov	14.8%	22.9%	62.3%						
Dec	12.1%	20.5%	67.4%						
Annual	14.6%	20.1%	65.2%	13.0%	16.6%	70.4%	(1.7%)	(3.5%)	5.2%

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through September 2009 (See 2008 SOM, Table 2-84)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.2%	15.6%	80.2%	4.4%	13.9%	81.7%	0.2%	(1.7%)	1.5%
Feb	4.5%	16.0%	79.5%	4.5%	12.7%	82.9%	(0.1%)	(3.3%)	3.4%
Mar	4.7%	16.0%	79.3%	4.3%	13.2%	82.5%	(0.4%)	(2.8%)	3.2%
Apr	5.0%	16.8%	78.2%	4.4%	14.1%	81.5%	(0.5%)	(2.7%)	3.3%
May	5.0%	18.2%	76.8%	4.6%	15.9%	79.5%	(0.4%)	(2.3%)	2.7%
Jun	5.5%	20.2%	74.3%	4.7%	14.2%	81.2%	(0.8%)	(6.1%)	6.9%
Jul	5.6%	20.4%	74.0%	5.6%	16.3%	78.2%	(0.0%)	(4.2%)	4.2%
Aug	4.9%	20.2%	75.0%	5.1%	15.5%	79.3%	0.3%	(4.6%)	4.4%
Sep	5.4%	19.3%	75.3%	4.7%	16.3%	78.9%	(0.7%)	(2.9%)	3.6%
Oct	5.4%	20.3%	74.3%						
Nov	5.6%	18.9%	75.5%						
Dec	4.6%	19.1%	76.3%						
Annual	5.0%	18.4%	76.5%	4.7%	14.5%	80.8%	(0.3%)	(4.0%)	4.3%

Table 3-1 2009 Calendar Year PJM RPM auction-clearing capacity prices and capacity revenues by LDA and zone: Effective for January through September 2009 (See 2008 SOM, Table 3-3)

	Delivery Year 2008/2009			Delivery Year 2009/2010			RPM Revenue 2009
Zone	LDA	$/MW-Day	$/MW in 2009	LDA	$/MW-Day	$/MW in 2009	(Jan - Sep) $/MW
AECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
AEP	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
AP	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
BGE	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
ComEd	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DAY	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DLCO	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
Dominion	RTO	$111.92	$16,900	RTO	$102.04	$12,449	$29,349
DPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
JCPL	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
Met-Ed	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PENELEC	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
Pepco	SWMAAC	$210.11	$31,727	SWMAAC	$237.33	$28,954	$60,681
PPL	RTO	$111.92	$16,900	MAAC+APS	$191.32	$23,341	$40,241
PSEG	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
RECO	EMAAC	$148.80	$22,469	MAAC+APS	$191.32	$23,341	$45,810
PJM	N/A	$124.58	$18,812	N/A	$138.46	$16,892	$35,703

Table 3-2 Capacity revenue by PJM zones (Dollars per MW-year): January through September 2009 (See 2008 SOM, Table 3-4)

Zone	2008 (Jan - Sep)	2009 (Jan - Sep)	Percent Change
AECO	$48,199	$45,810	(5%)
AEP	$19,856	$29,349	48%
AP	$19,856	$40,241	103%
BGE	$54,292	$60,681	12%
ComEd	$19,856	$29,349	48%
DAY	$19,856	$29,349	48%
DLCO	$19,856	$29,349	48%
Dominion	$19,856	$29,349	48%
DPL	$48,199	$45,810	(5%)
JCPL	$48,199	$45,810	(5%)
Met-Ed	$19,856	$40,241	103%
PECO	$48,199	$45,810	(5%)
PENELEC	$19,856	$40,241	103%
Pepco	$54,292	$60,681	12%
PPL	$19,856	$40,241	103%
PSEG	$48,199	$45,810	(5%)
RECO	$48,199	$45,810	(5%)
PJM	$28,588	$35,703	25%

Figure 3-1 New entrant CT zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-3)

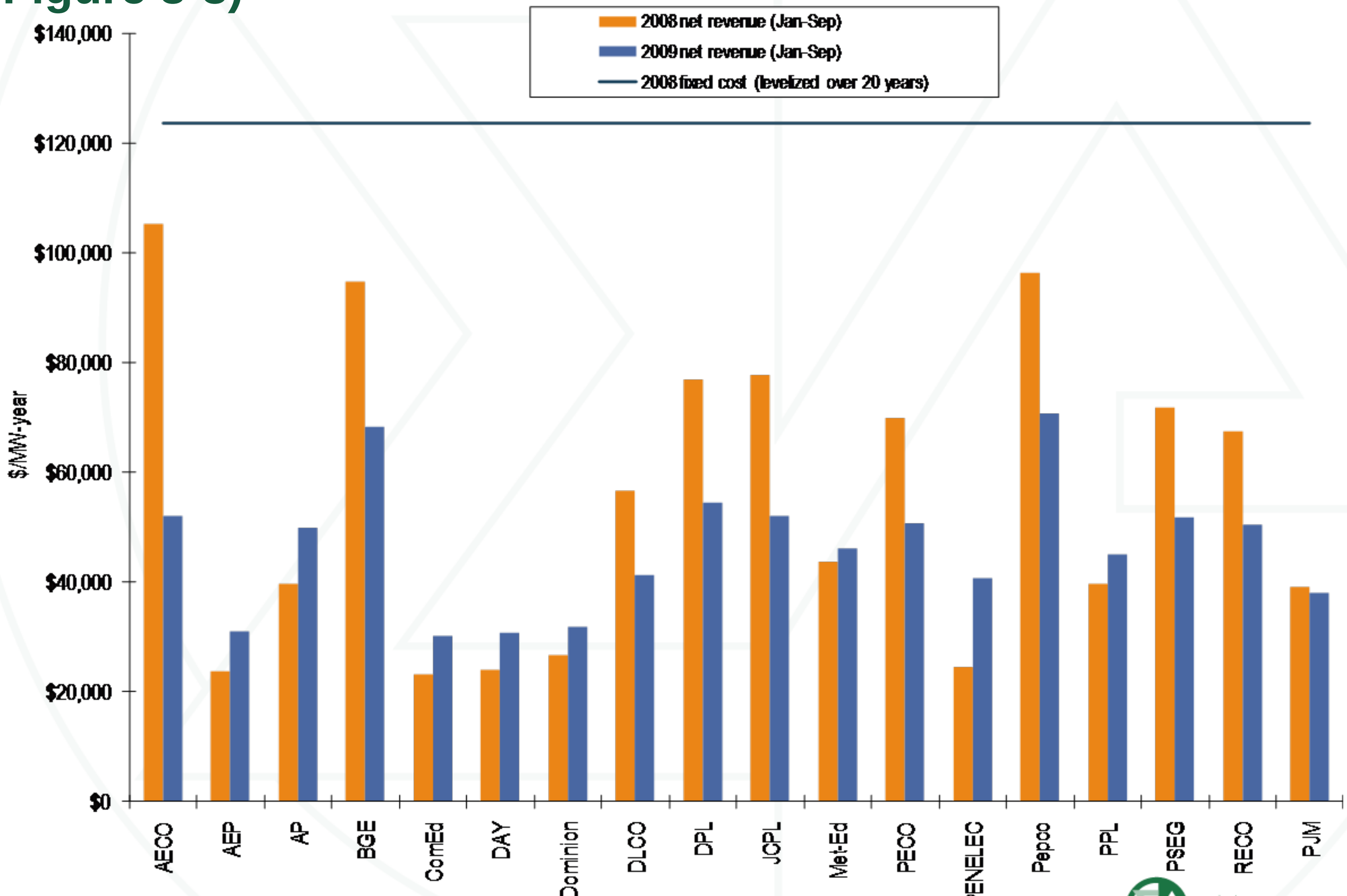

Figure 3-2 New entrant CC zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-5)

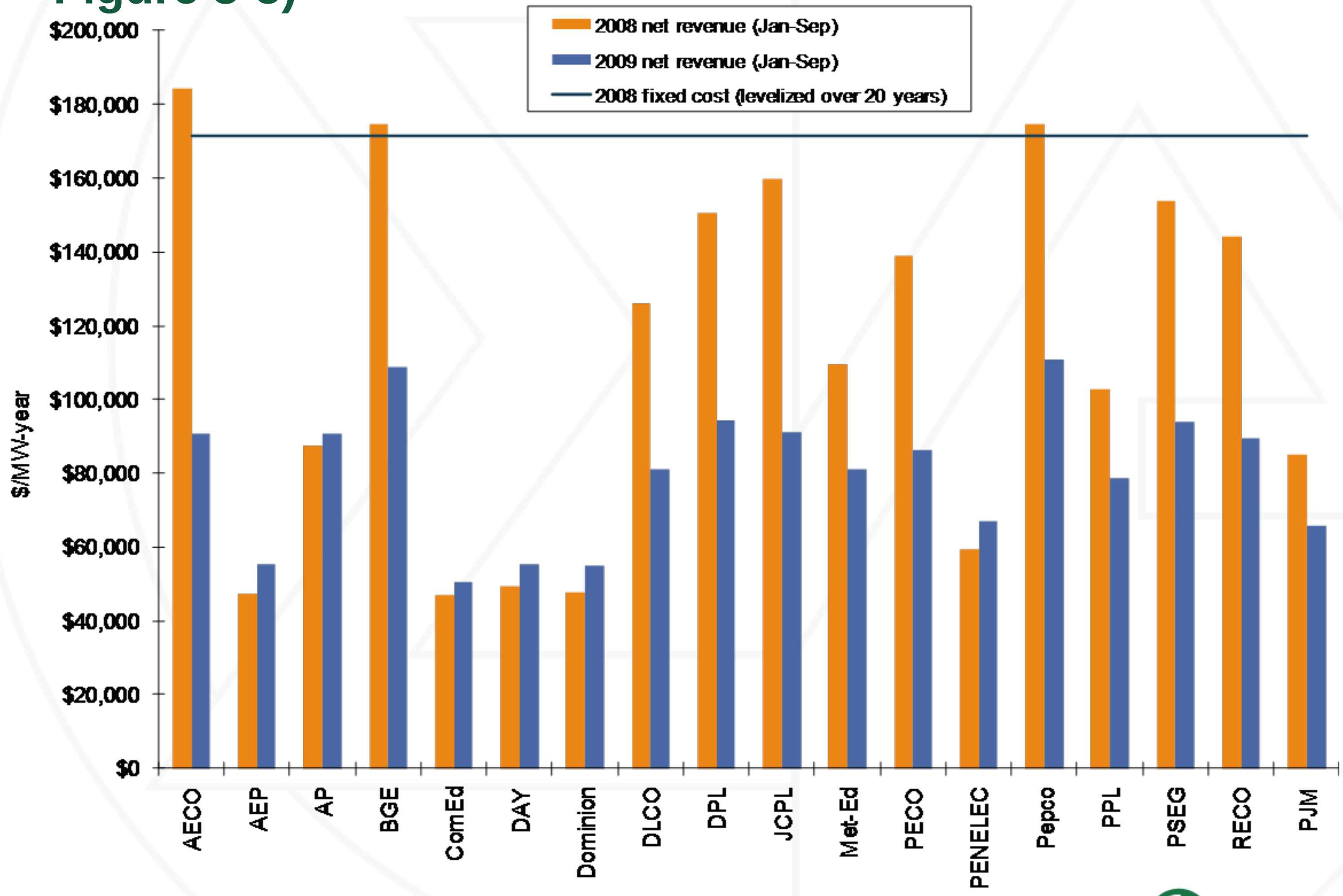

Figure 3-3 New entrant CP zonal net revenue with 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): January through September 2008 and 2009 (See 2008 SOM, Figure 3-7)

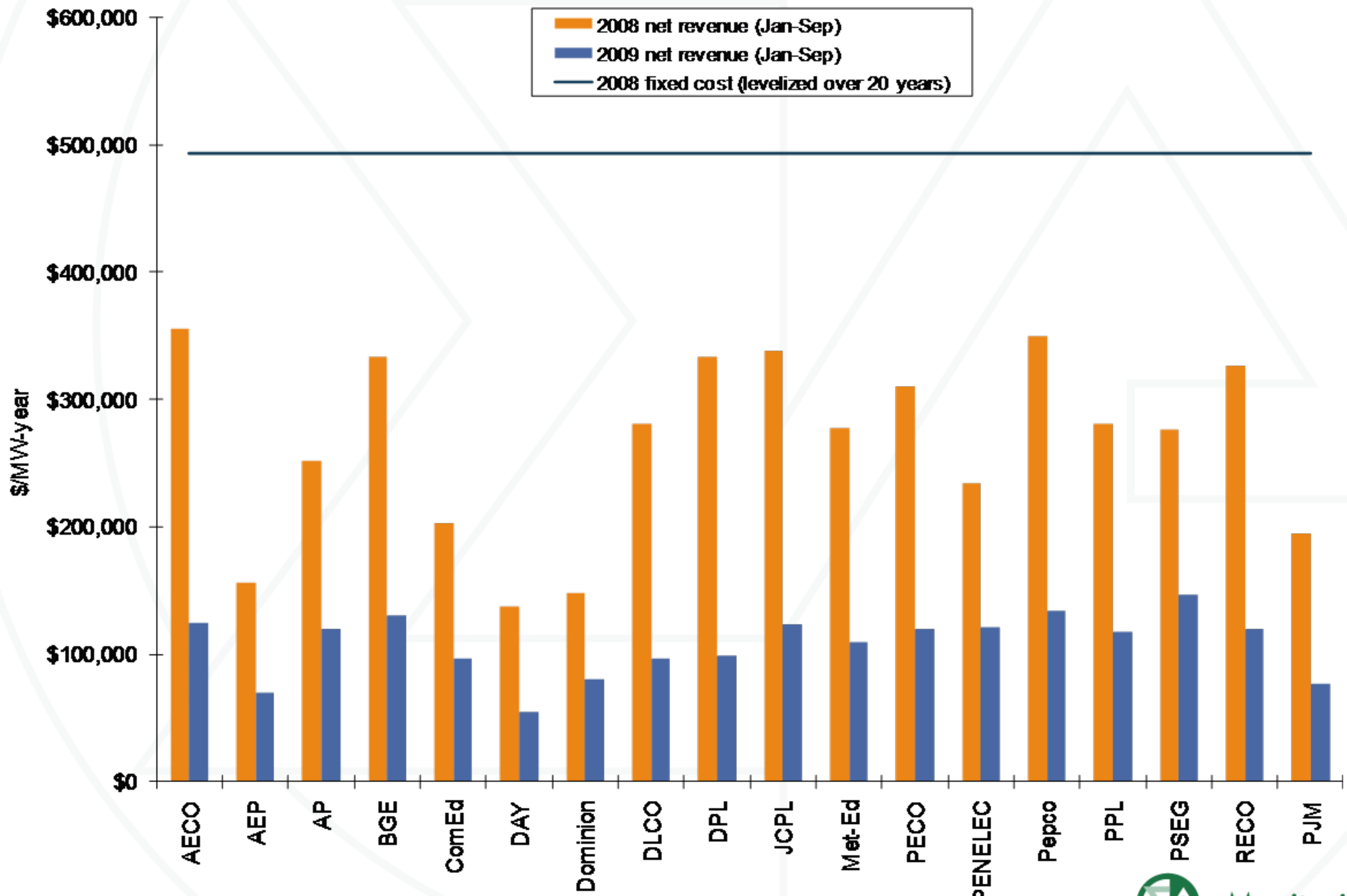

Table 3-23 PJM installed capacity (By fuel source): January 1, May 31, June 1, September 30, 2009 (See 2008 SOM, Table 3-30)

	1-Jan-09		31-May-09		1-Jun-09		30-Sep-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%	68,137.6	40.7%
Gas	**48,333.9**	**29.3%**	**48,506.9**	**29.4%**	**48,979.3**	**29.2%**	**48,810.6**	**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%**	**30,701.5**	**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%**	**167,268.7**	**100.0%**

Table 3-24 PJM generation (By fuel source (GWh)): January through September 2009 (See 2008 SOM, Table 3-31)

	GWh	Percent
Coal	263,486.1	50.3%
Nuclear	187,626.8	35.8%
Natural Gas	52,694.5	10.1%
Hydroelectric	10,280.2	2.0%
Wind	3,446.5	0.7%
Solid Waste	3,125.5	0.6%
Miscellaneous	1,176.3	0.2%
Heavy Oil	1,127.0	0.2%
Landfill Gas	1,007.9	0.2%
Light Oil	156.5	0.0%
Kerosene	7.0	0.0%
Solar	2.9	0.0%
Biomass Gas	2.1	0.0%
Battery	0.1	0.0%
Jet Oil	0.0	0.0%
Total	524,139.5	100.0%

Table 3-33 Capacity factor of wind units in PJM, January through September 2009 (New Table)

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	24.9%	122,624	1,744
Capacity Resource	**27.5%**	**69,361**	**798**
All Units	26.0%	191,985	2,542

Table 3-34 Wind resources in Real-Time offering at a negative price in PJM, June through September 2009 (New Table)

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	83.0	85	0.15%
All Wind	**828.9**	**473**	**0.81%**

Figure 3-4 Average hourly real-time generation of wind units in PJM, January through September 2009 (New Figure)

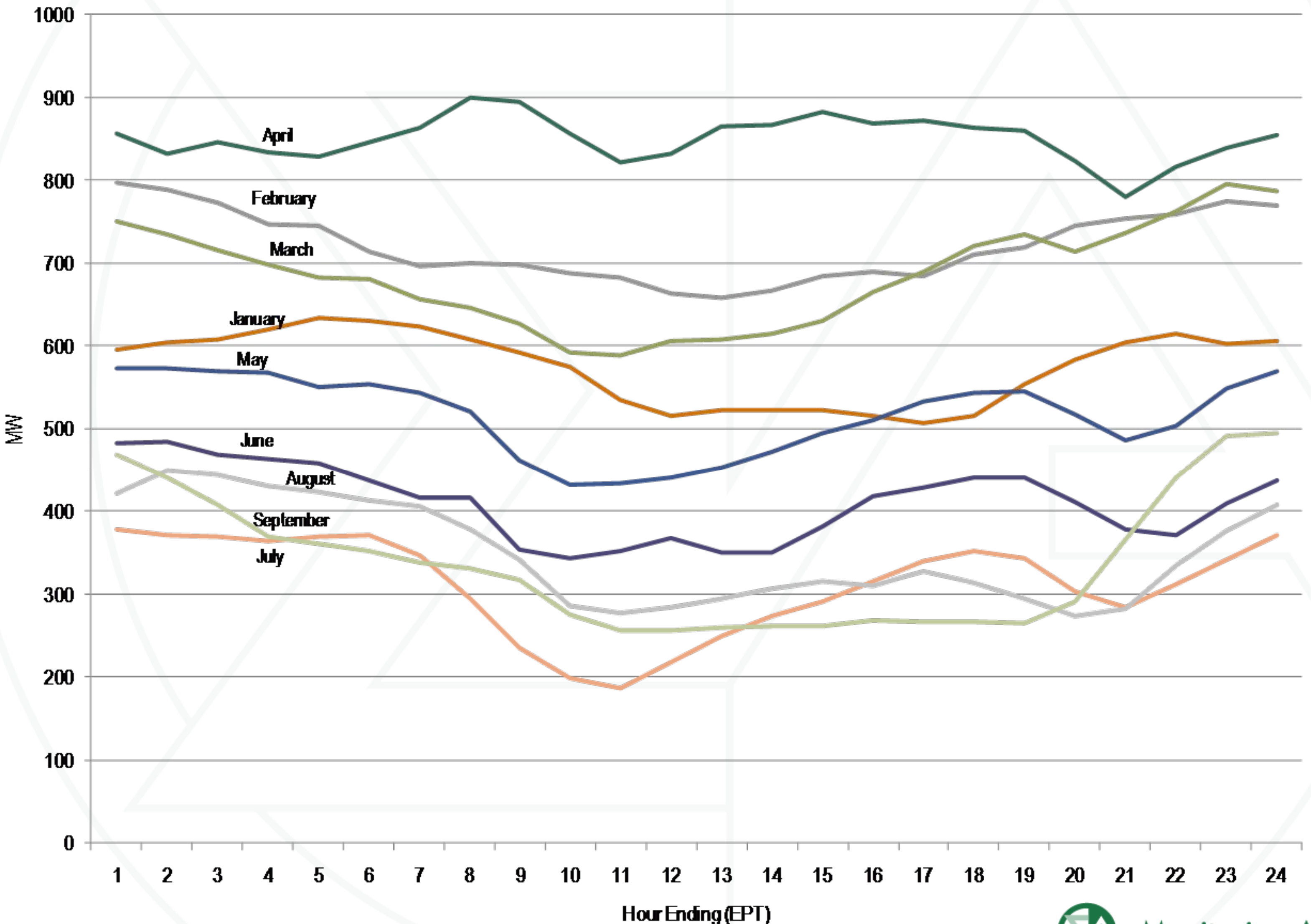

Figure 3-6 Marginal fuel displacement by wind generation in PJM, January through September 2009 (New Figure)

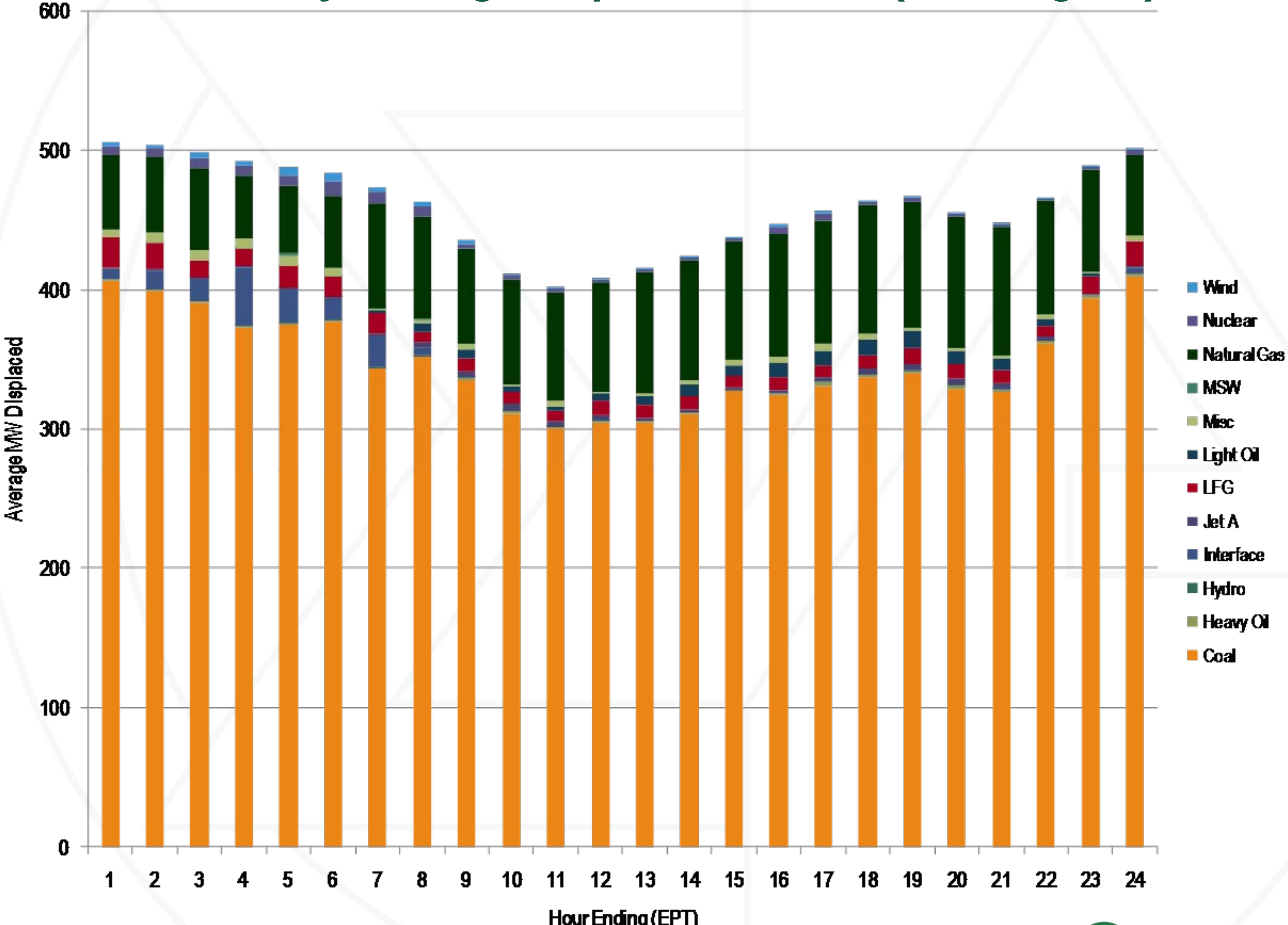

Table 3-35 Monthly operating reserve charges: January through September 2008 and 2009 (See 2008 SOM, Table 3-45)

	2008 (Jan-Sep) Charges				2009 (Jan-Sep) Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$30,001,637	$40,590,601
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,508,010	$24,781,756
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$25,945,310	$35,603,936
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,246,434	$20,264,727
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,476,784	$21,506,435
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,224,687	$25,947,016
Jul	$7,038,834	$874,234	$48,041,415	$55,954,483	$8,210,636	$38,643	$17,312,974	$25,562,253
Aug	$6,140,554	$143,857	$26,212,547	$32,496,959	$7,697,174	$1	$20,711,506	$28,408,680
Sep	$4,581,147	$405,308	$27,809,898	$32,796,353	$6,057,598	$13,611	$13,450,468	$19,521,678
Total	$50,673,931	$3,318,419	$295,208,680	$349,201,030	$67,954,390	$2,354,884	$171,877,810	$242,187,084
Share of Annual Charges	14.5%	1.0%	84.5%	100.0%	28.1%	1.0%	71.0%	100.0%

Table 3-36 Regional balancing charges allocation: January through September 2008 and 2009 (New table)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$3,432,227	$134,849	$3,567,076	$49,355,811	$28,883,393	$14,803,890	$93,043,094	$96,610,170
RTO	2.6%	0.1%	2.7%	37.9%	22.2%	11.4%	71.5%	74.2%
East	$393,809	$13,683	$407,492	$5,824,239	$3,067,879	$1,559,973	$10,452,090	$10,859,583
East	0.3%	0.0%	0.3%	4.5%	2.4%	1.2%	8.0%	8.3%
West	$18,628,965	$829,980	$19,458,945	$1,640,297	$1,080,901	$560,559	$3,281,757	$22,740,702
West	14.3%	0.6%	14.9%	1.3%	0.8%	0.4%	2.5%	17.5%
Total	$22,455,001	$978,512	$23,433,513	$56,820,347	$33,032,173	$16,924,422	$106,776,941	$130,210,454
Total	17.2%	0.8%	18.0%	43.6%	25.4%	13.0%	82.0%	100.0%

Table 3-39 Average regional balancing operating reserve rates: January through September 2009 (See 2008 SOM, Table 3-48)

	Reliability	Deviations
RTO	0.0062	0.6479
East	0.0014	0.1219
West	0.0872	0.0568

Figure 3-9 Operating reserve credits: January through September 2009 (See 2008 SOM, Figure 3-11)

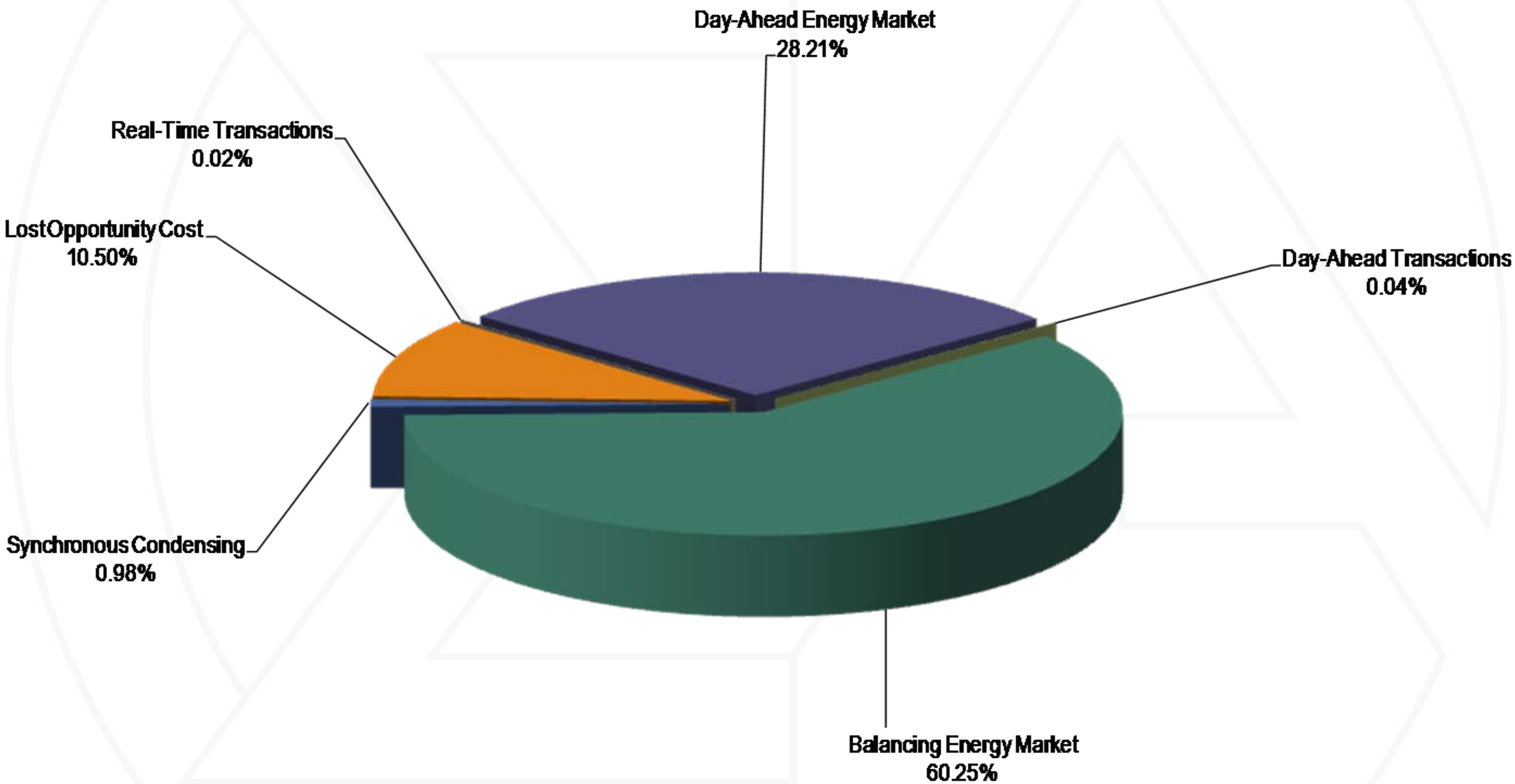

Table 3-47 Top 10 units and organizations receiving total operating reserve credits: January through September 2009 (See 2008 SOM, Table 3-57)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$24,528,324	10.2%	10.2%	$70,296,769	29.2%	29.2%
2	$17,238,165	7.2%	17.4%	$48,586,092	20.2%	49.4%
3	$10,021,474	4.2%	21.5%	$24,600,093	10.2%	59.7%
4	$8,495,009	3.5%	25.1%	$15,209,491	6.3%	66.0%
5	$6,847,966	2.8%	27.9%	$13,079,299	5.4%	71.4%
6	$5,983,837	2.5%	30.4%	$10,049,183	4.2%	75.6%
7	$3,423,767	1.4%	31.8%	$8,715,685	3.6%	79.3%
8	$3,362,806	1.4%	33.2%	$5,556,467	2.3%	81.6%
9	$3,360,659	1.4%	34.6%	$4,086,988	1.7%	83.3%
10	$2,855,522	1.2%	35.8%	$3,729,968	1.6%	84.8%

Table 3-54 Regional balancing operating reserve credits: January through September 2009 (New table)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$3,567,076	$93,043,094	$96,610,170
East	$407,492	$10,452,090	$10,859,583
West	$19,458,945	$3,281,757	$22,740,702
Total	$23,433,513	$106,776,941	$130,210,454

Table 3-55 Total deviations: January through September 2009 (New table)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	72,956,743	42,432,853	21,193,699	136,583,296

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through September 2009 (See 2008 SOM, Figure 4-3)

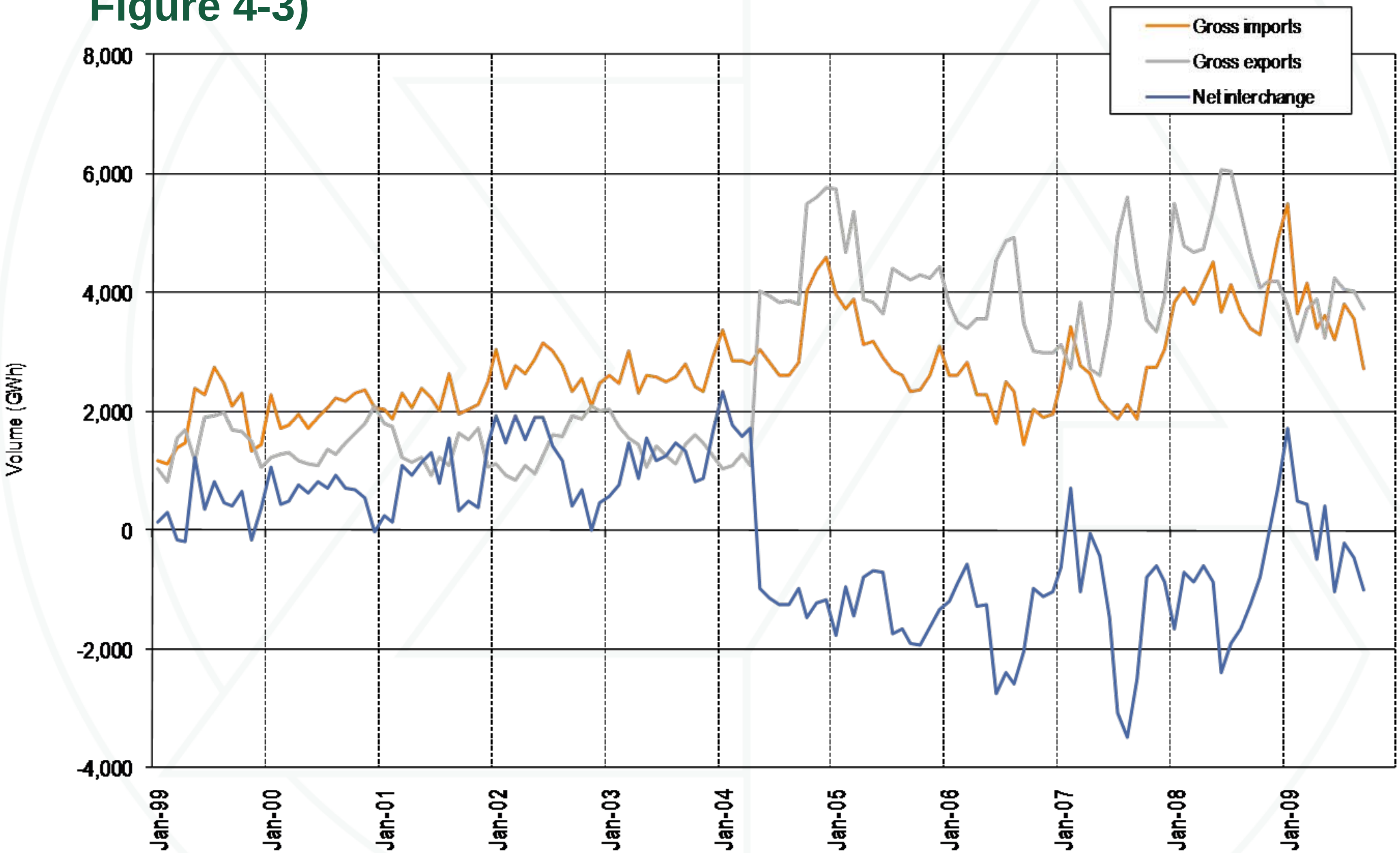

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: January through September 2009 (See 2008 SOM, Figure 4-9)

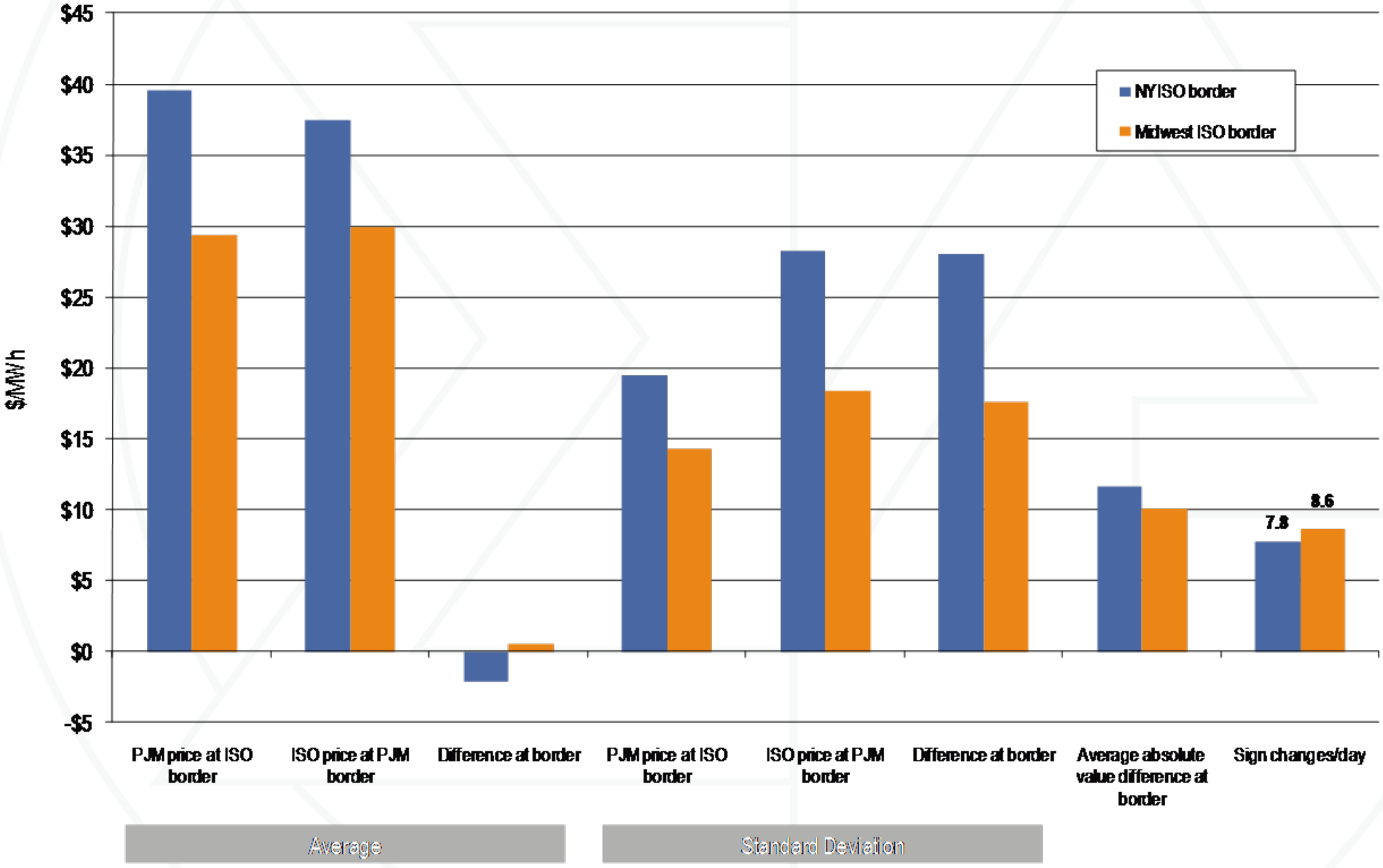

Figure 4-15 Credits for coordinated congestion management: January through September 2009 (See 2008 SOM, Figure 4-10)

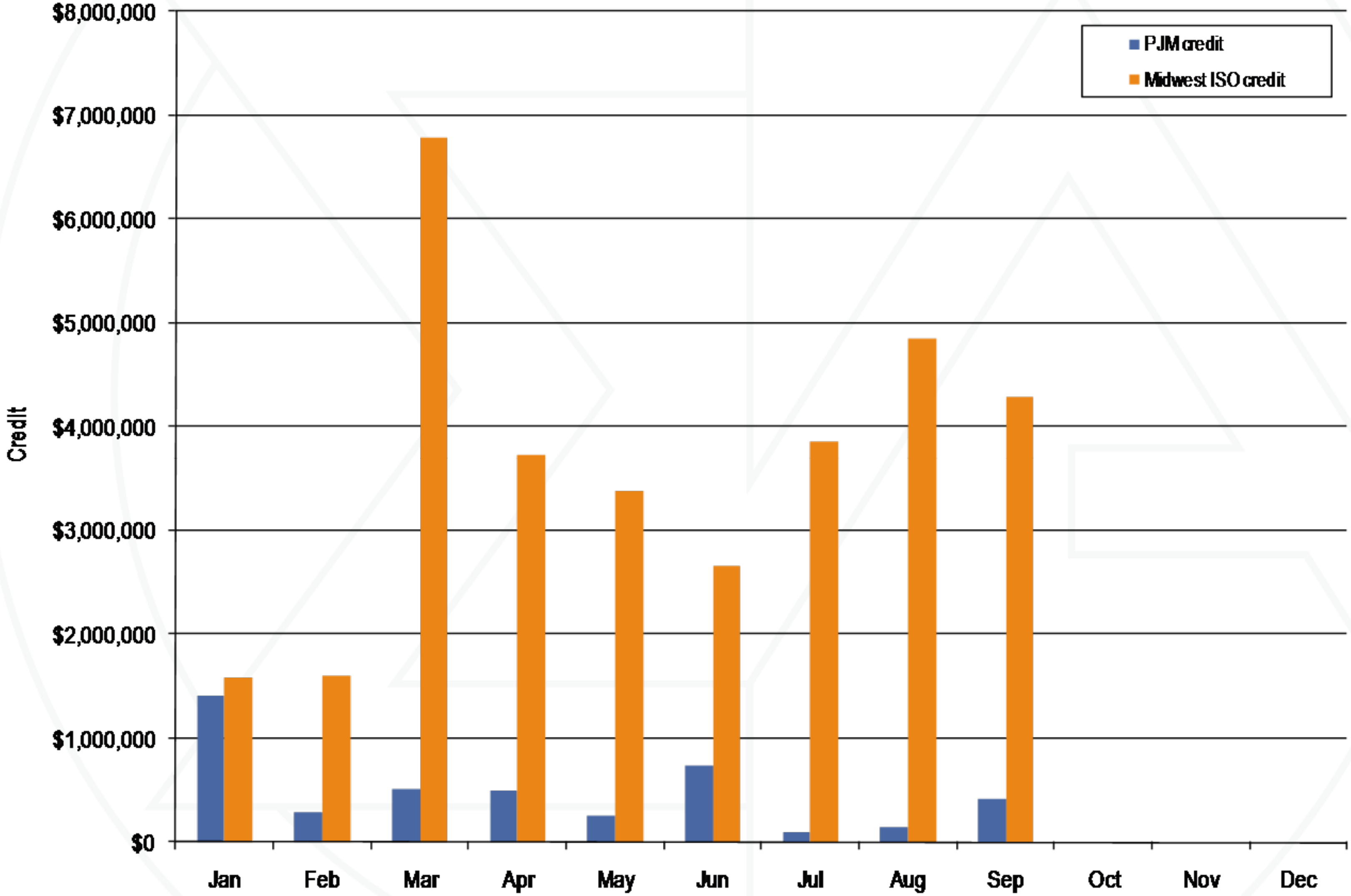

Figure 4-22 Spot import service utilization: January through September 2009 (See 2008 SOM, Figure 4-12)

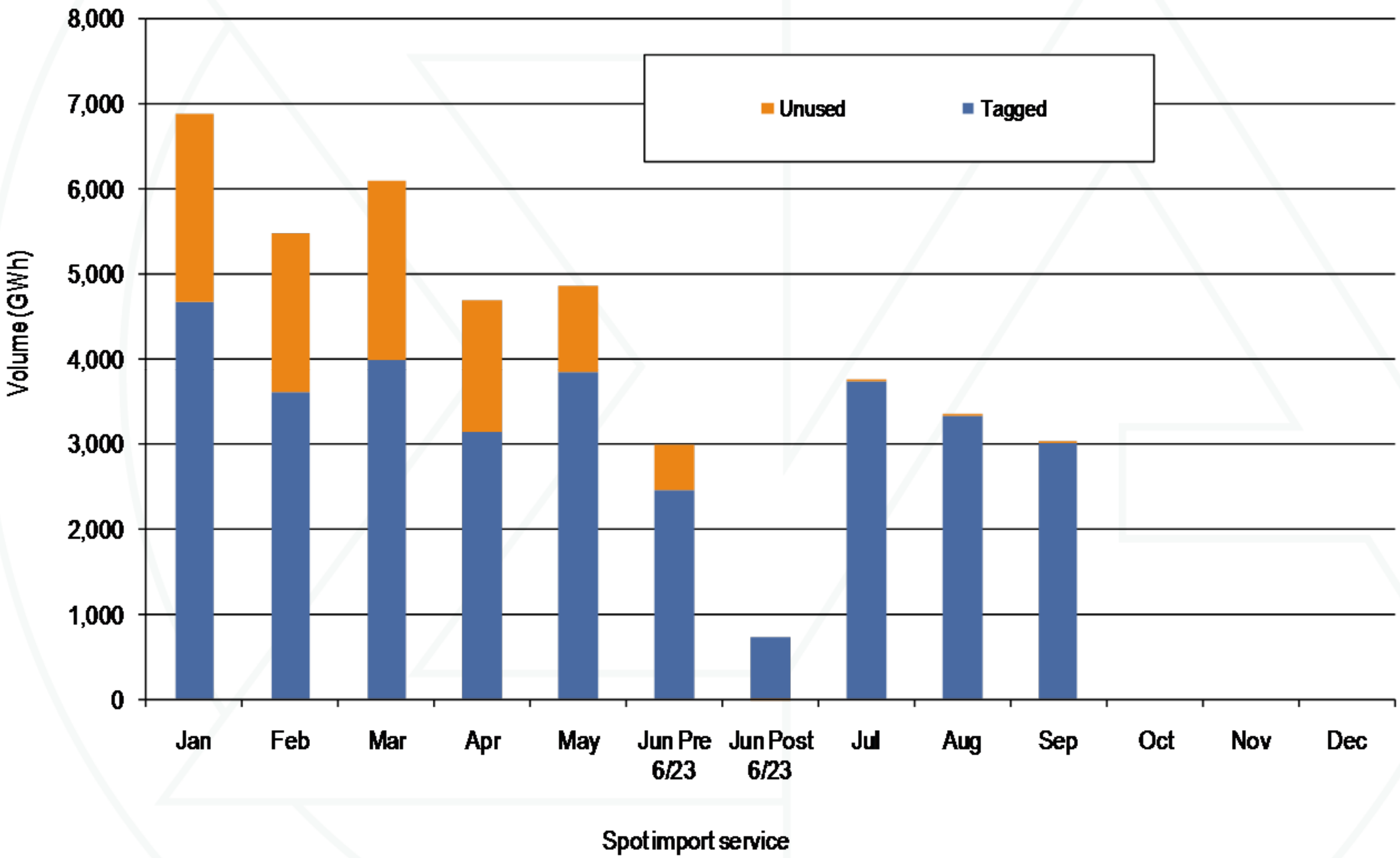

Table 5-7 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2008 SOM, Table 5-10)

	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 (See 2008 SOM, Figure 5-1)

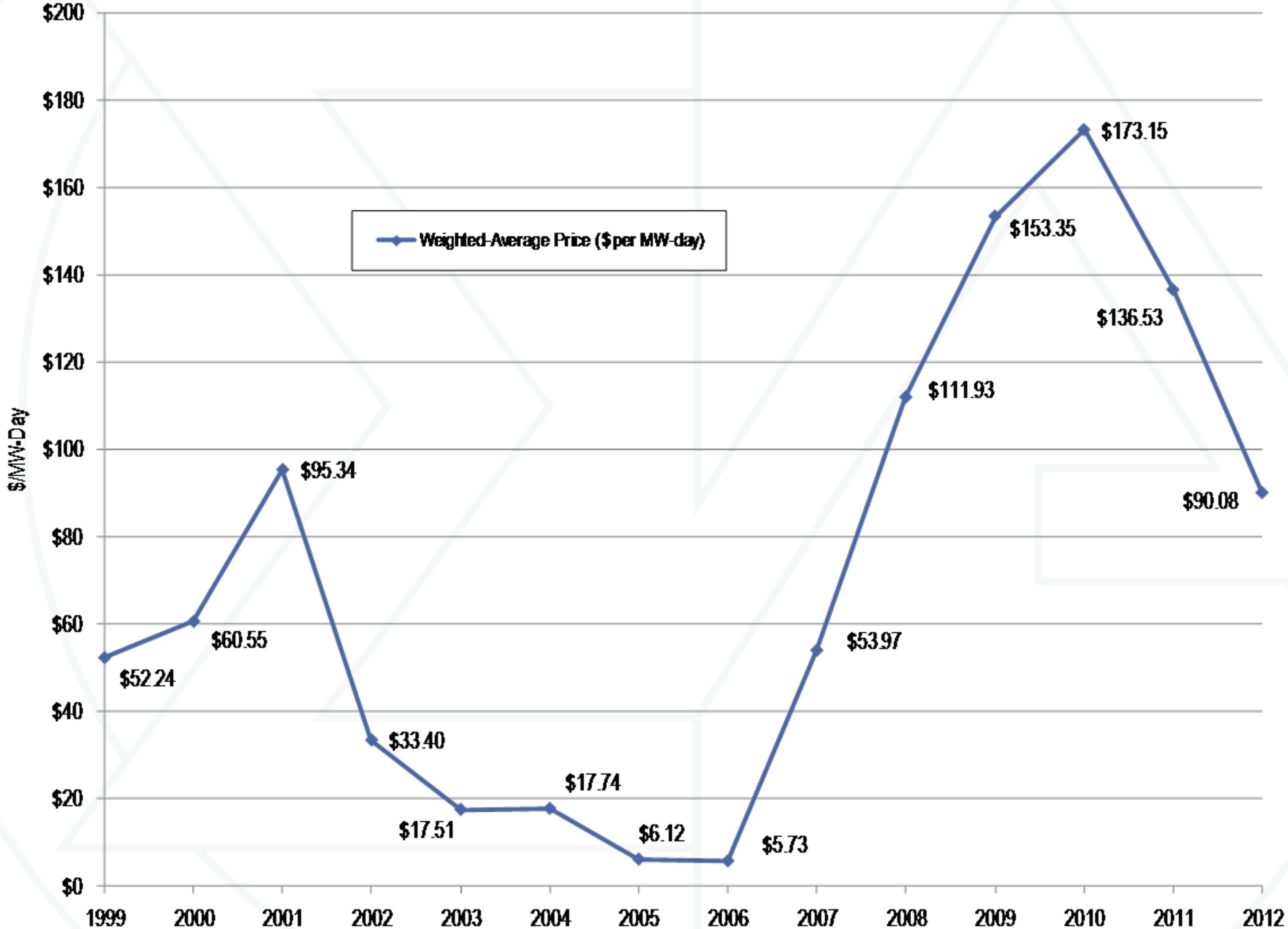

Figure 5-3 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Figure 5-8)

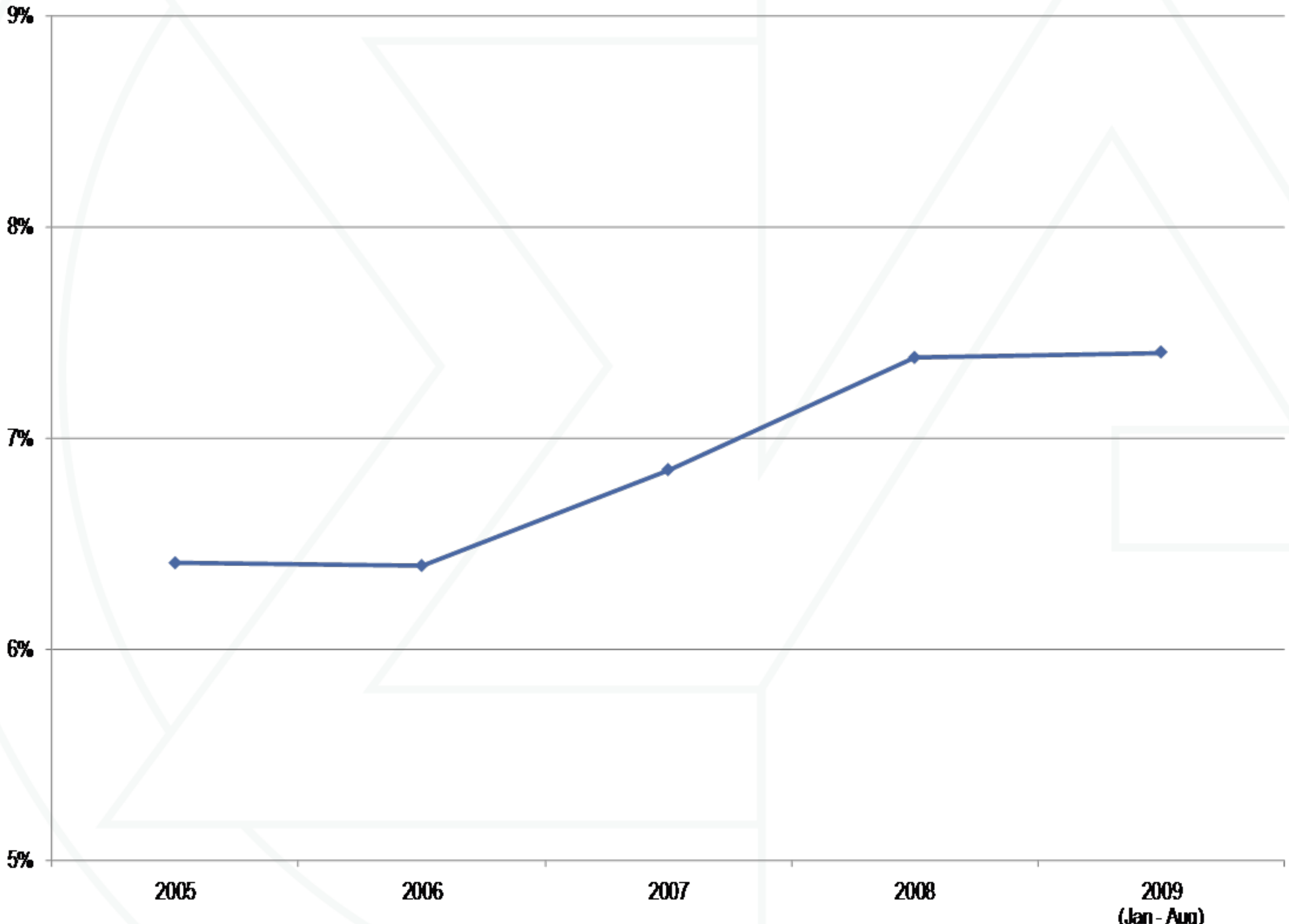

Table 5-9 Contribution to EFORd by unit type (Percentage points): Calendar years 2005 to 2009 (January through August) (See 2008 SOM Table 5-17)

	2004	2005	2006	2007	2008	2009 (Jan - Aug)
Combined Cycle	0.5	0.6	0.5	0.4	0.4	0.5
Combustion Turbine	**1.3**	**1.3**	**1.4**	**1.6**	**1.5**	**1.4**
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	**0.2**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Nuclear	0.6	0.3	0.3	0.2	0.4	0.8
Steam	**4.7**	**4.1**	**4.1**	**4.4**	**4.9**	**4.6**
Total	7.3	6.4	6.4	6.8	7.4	7.4

Table 5-12 Contributions to Economic Outages: January through August 2009 (See 2008 SOM Table 5-21)

	Contribution to Economic Reasons
Lack of Fuel (OMC)	90.7%
Lack of Fuel (Non-OMC)	**5.4%**
Other Economic Problems	2.3%
Lack of Water (Hydro)	**1.4%**
Fuel Conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	**0.0%**
Total	100.0%

Table 5-15 PJM EFORd vs. XEFORd by unit type: January through August 2009 (See 2008 SOM Table 5-24)

	EFORd	XEFORd	Difference
Combined Cycle	3.7%	3.5%	0.2%
Combustion Turbine	8.8%	7.6%	1.2%
Diesel	9.7%	8.2%	1.5%
Hydroelectric	2.8%	2.6%	0.1%
Nuclear	4.2%	4.1%	0.0%
Steam	9.6%	8.3%	1.3%
Total	7.4%	6.6%	0.8%

Table 5-19 PJM EFORd and EFORp data by unit type: Calendar year 2009 (January through August) (New table)

	EFORd	EFORp	Difference
Combined Cycle	3.7%	2.1%	1.6%
Combustion Turbine	**8.8%**	**2.4%**	**6.4%**
Diesel	9.7%	4.9%	4.8%
Hydroelectric	**2.8%**	**2.9%**	**(0.2%)**
Nuclear	4.2%	4.1%	0.1%
Steam	**9.6%**	**4.6%**	**5.0%**
Total	7.4%	3.8%	3.6%

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through September 2009 (See 2008 SOM Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,629	6,313	83%	2,563	34%
Off Peak	**7,629**			**2,236**	**29%**
On Peak	7,629			2,925	38%

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through September 2009 (See 2008 SOM Figure 6-2)

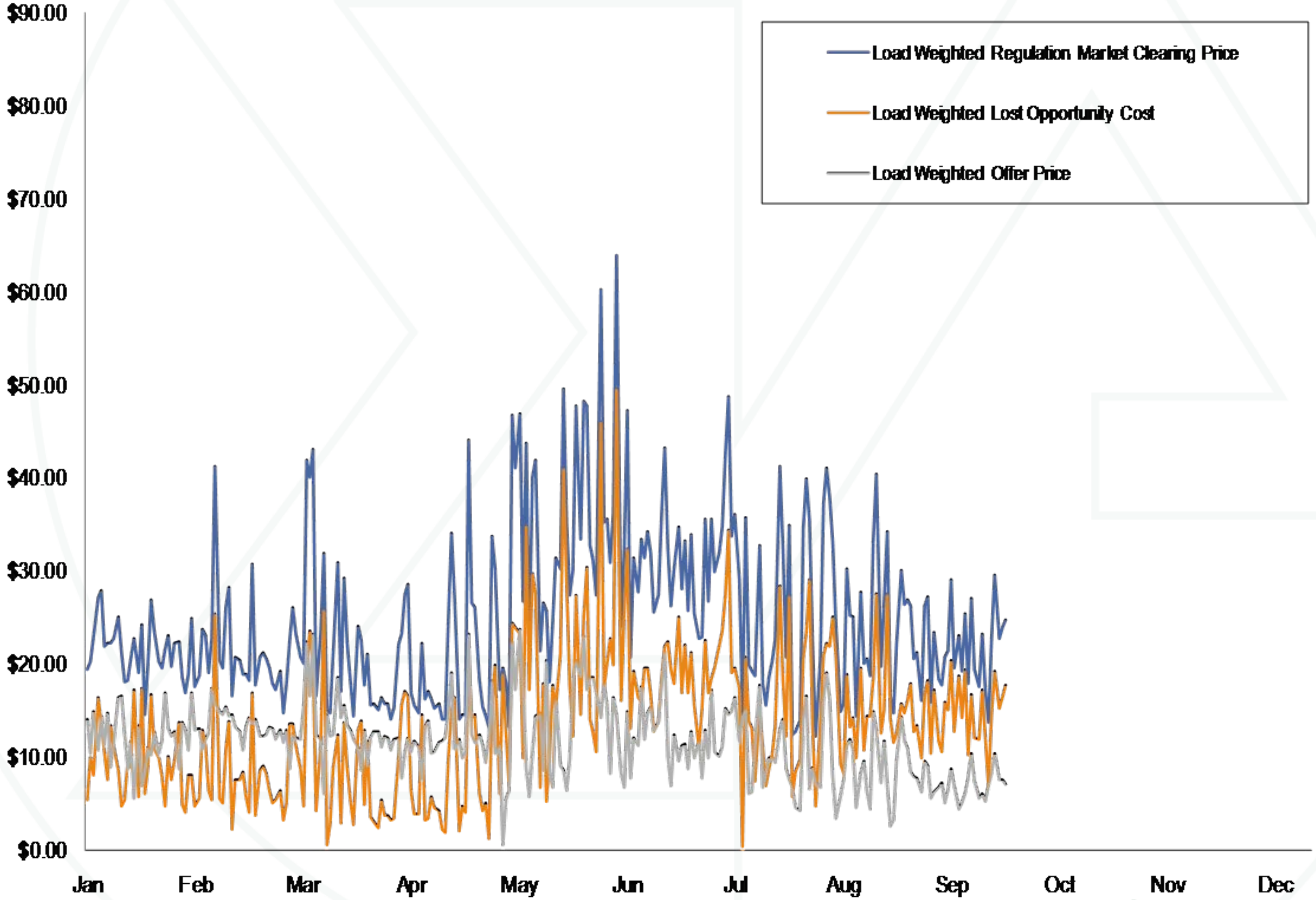

Figure 6-3 Monthly average regulation demand (required) vs. price: January through September 2009 (See 2008 SOM Figure 6-3)

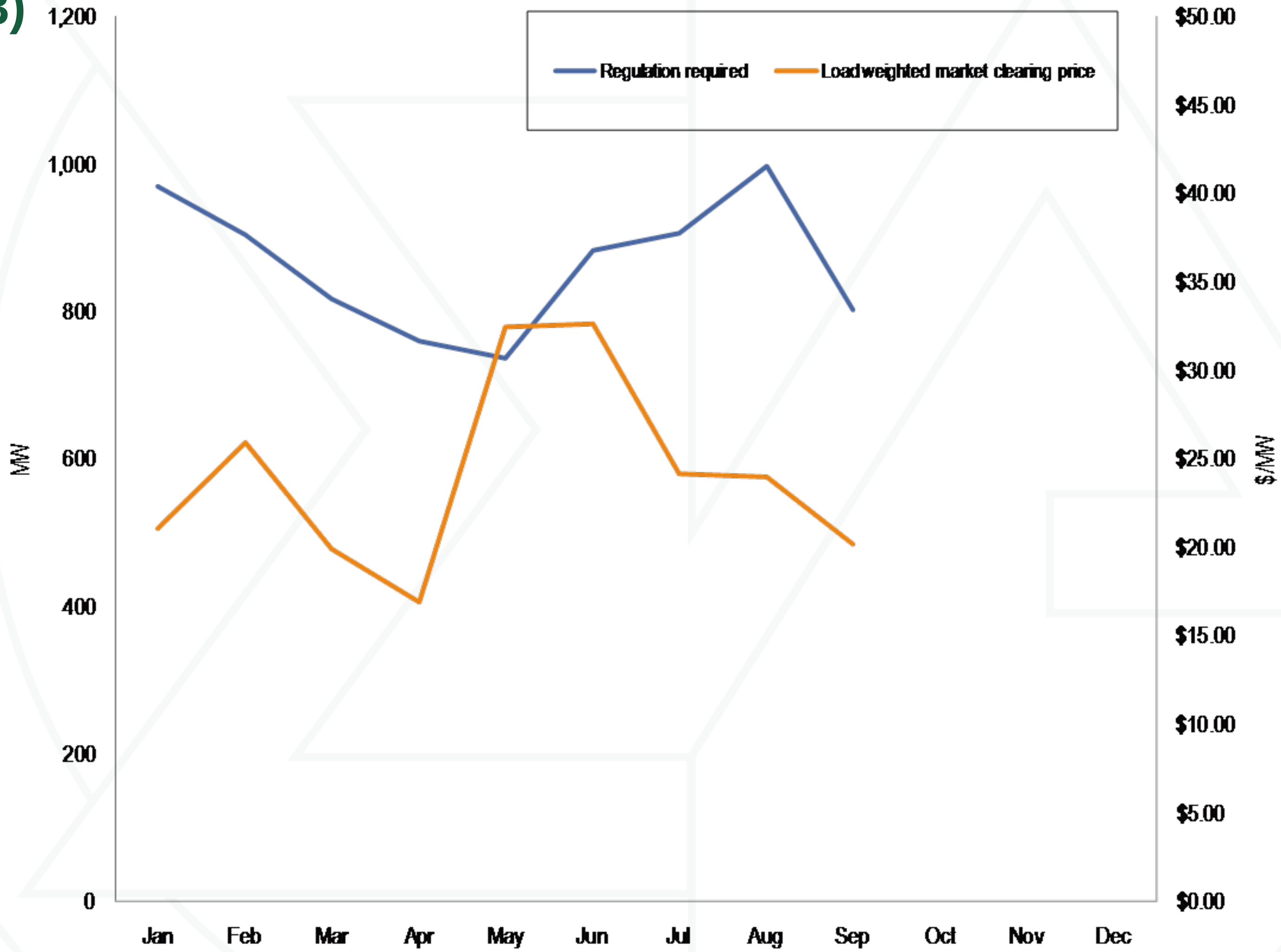

Figure 6-4 Monthly load weighted, average regulation cost and price: January through September 2009 (See 2008 SOM Figure 6-4)

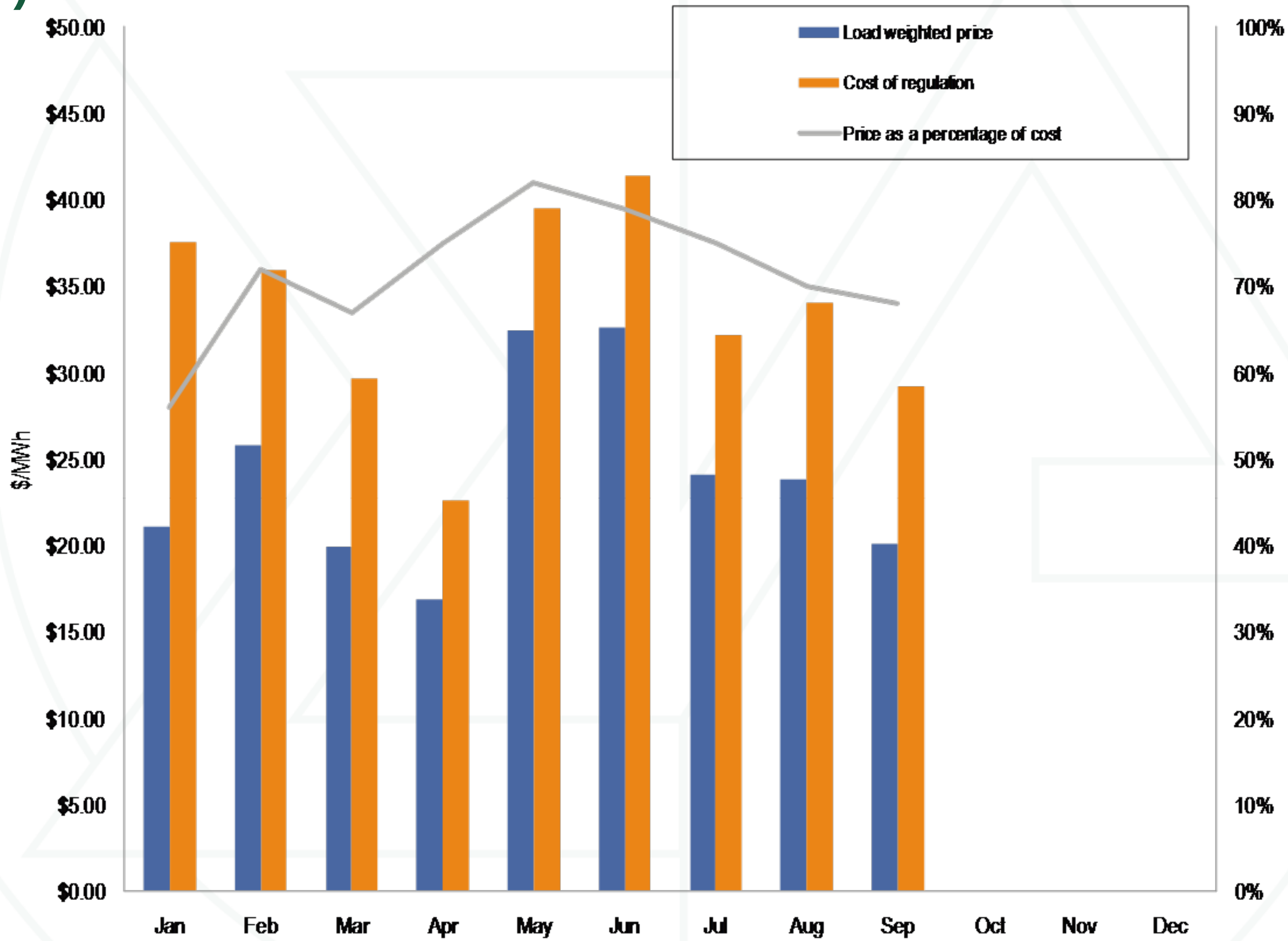

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2009 (See 2008 SOM Figure 6-5)

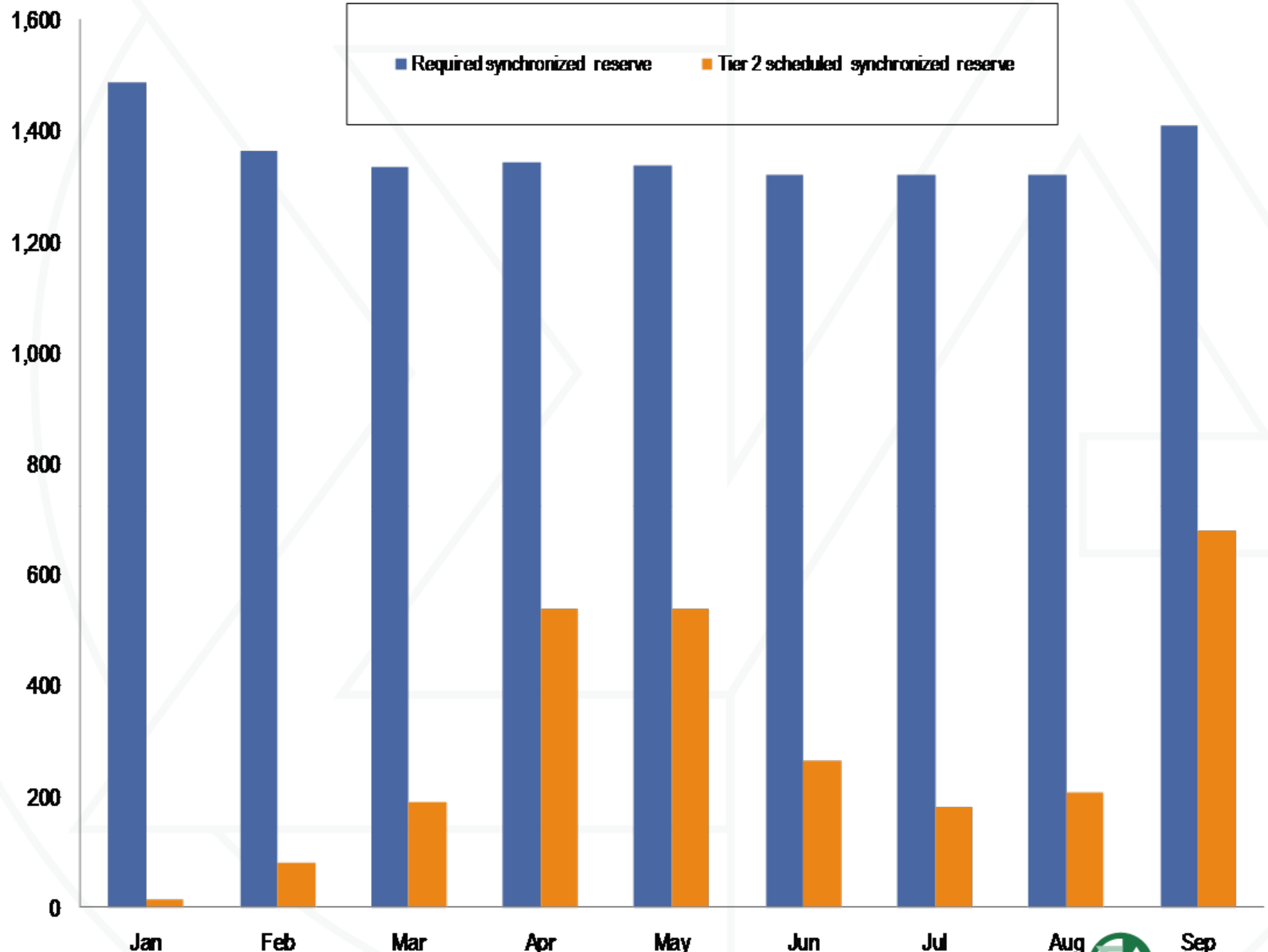

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2009 (See 2008 SOM Figure 6-6)

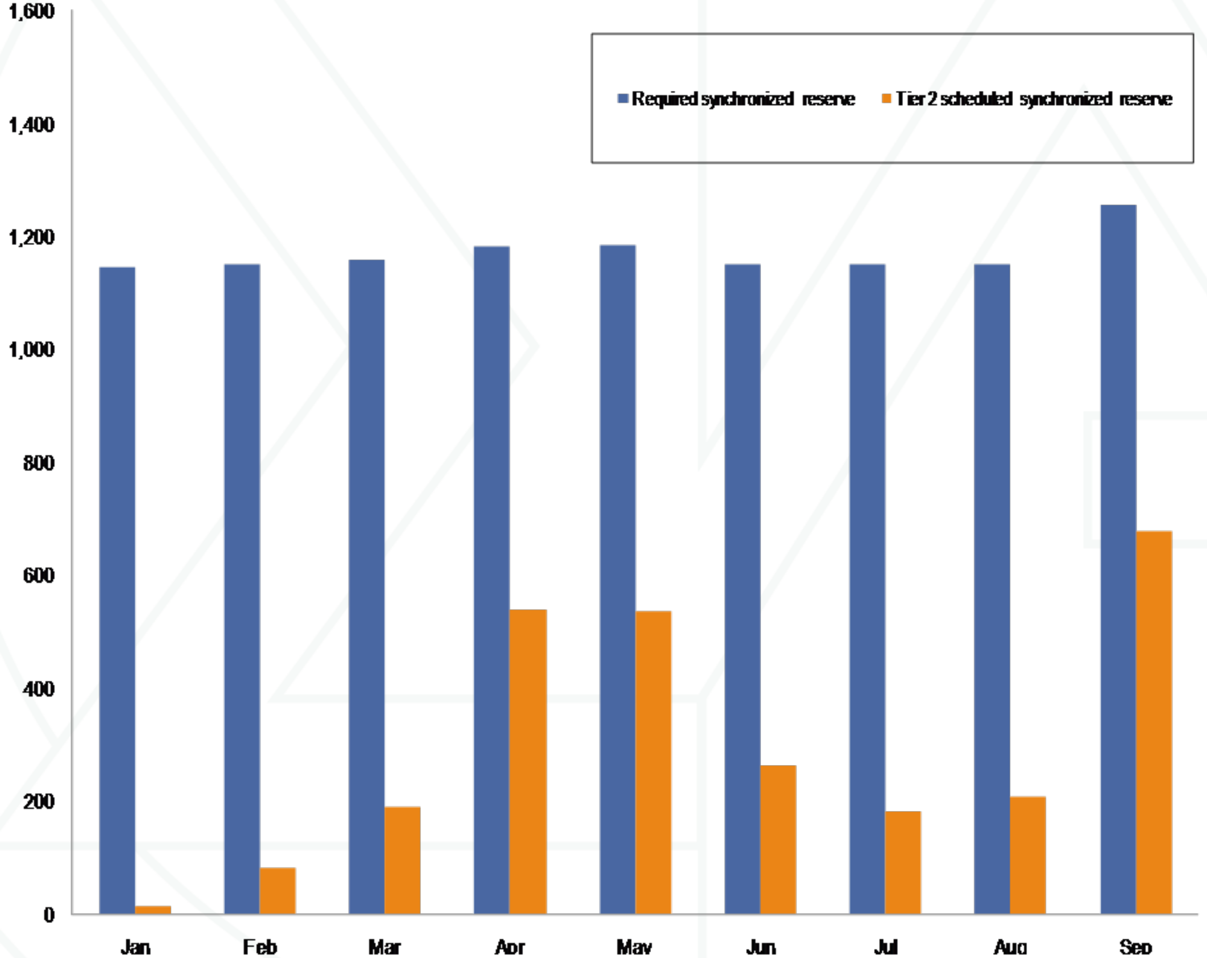

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through September 2009 (See 2008 SOM Figure 6-10)

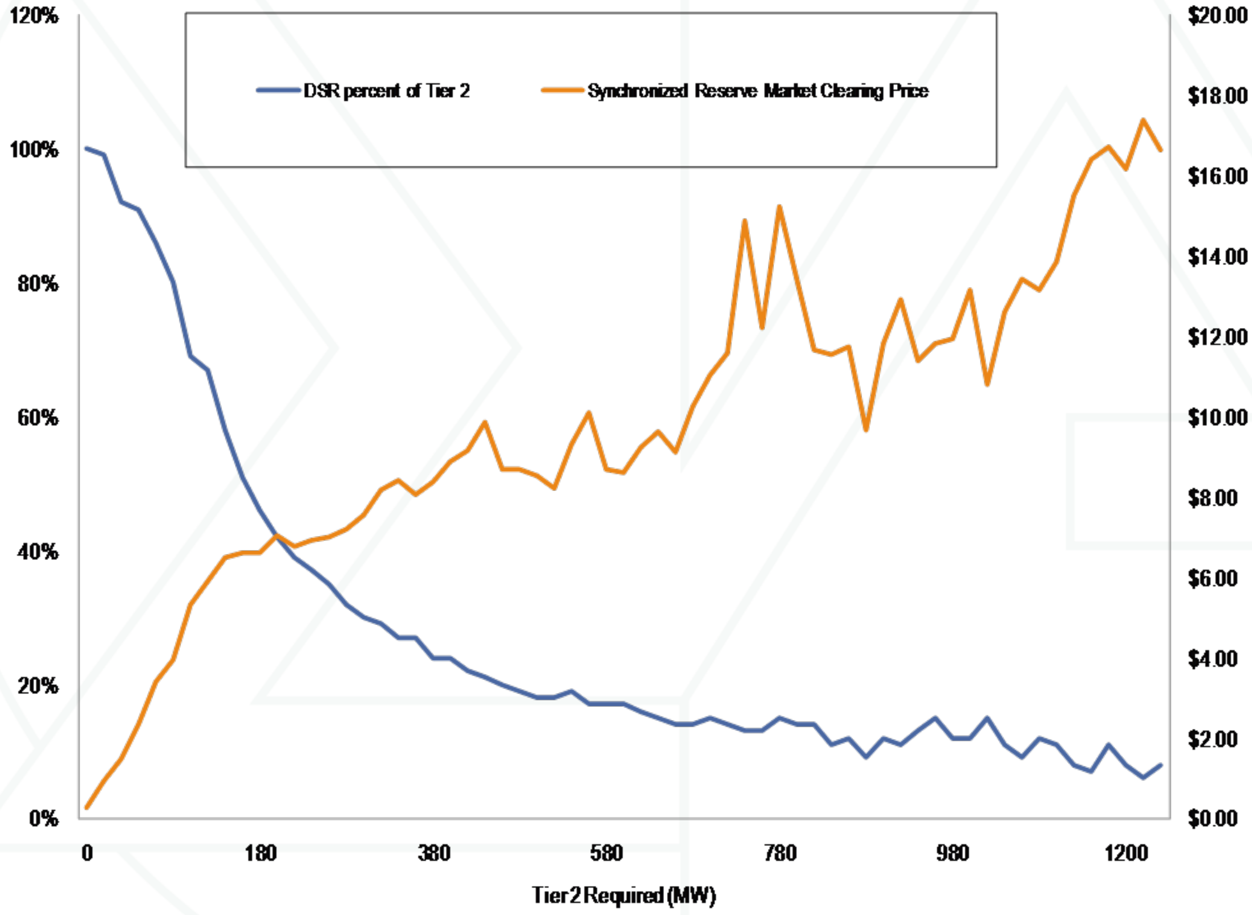

Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through September 2009 (See 2008 SOM Figure 6-13)

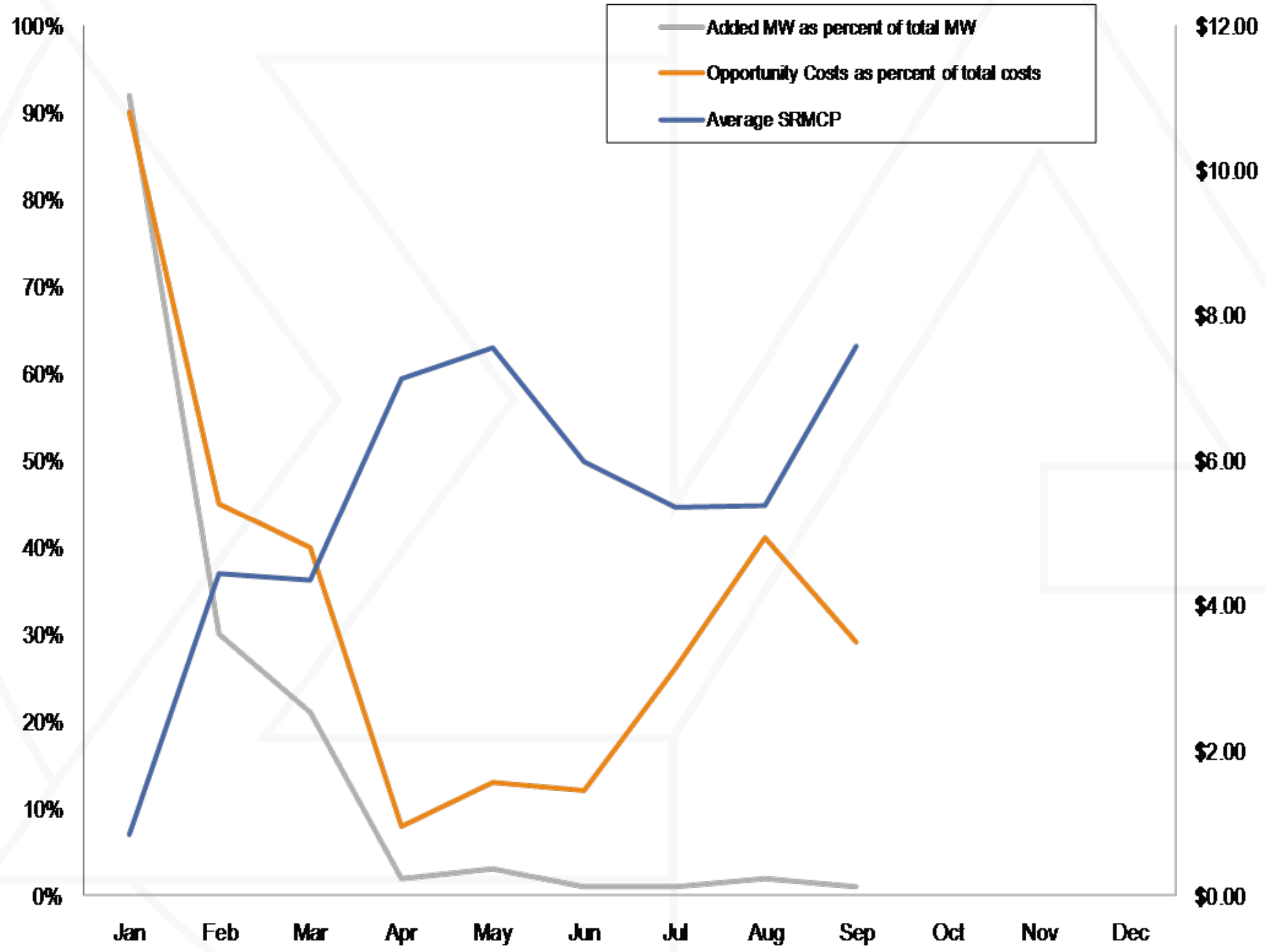

Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2009 (See 2008 SOM Figure 6-14)

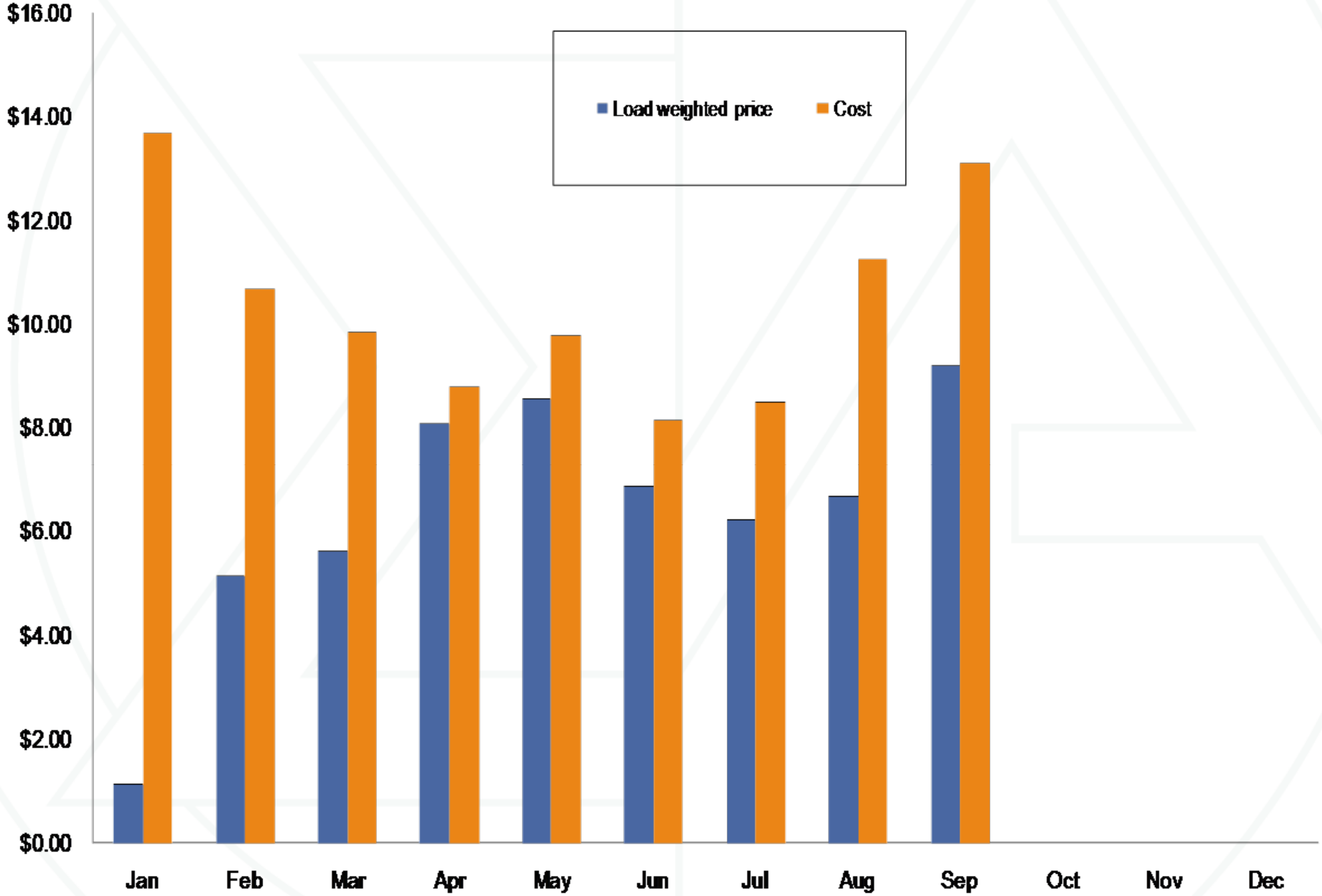

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2009 (See 2008 SOM Figure 6-15)

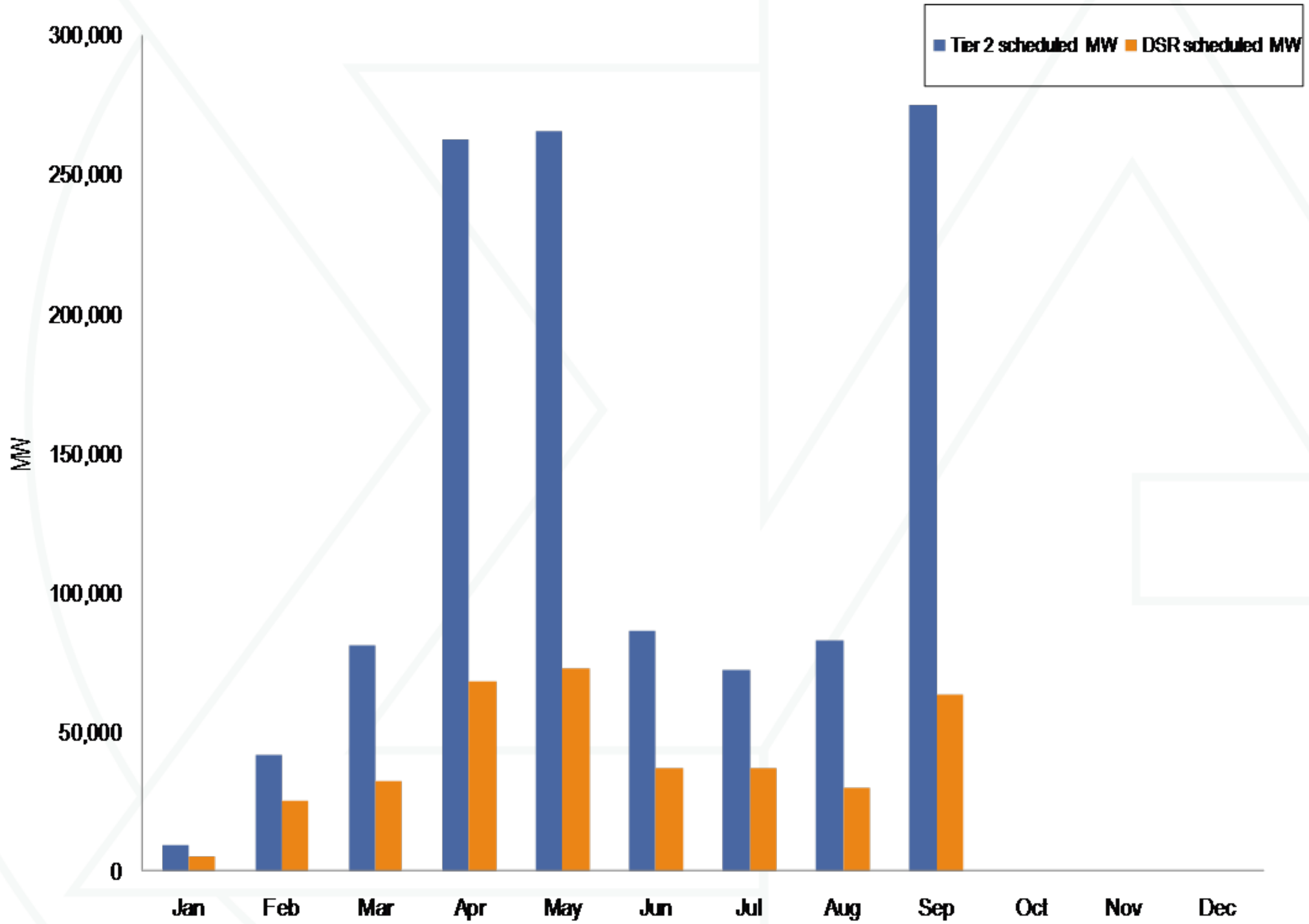

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to September 2009 (See 2008 SOM Table 7-1)

	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	$544	NA	$19,932	3%
Total	$9,415		$143,969	7%

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): January through September 2008 and 2009 (New Table)

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2008 (Jan-Sep)	$921.9	($880.7)	($24.5)	$1,778.2
2009 (Jan-Sep)	$210.6	($380.9)	($48.0)	$543.6

Table 8-11 ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010 (See 2008 SOM Table 8-28)

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*	**$426,023,336**	**$199,335,975**	**$454,904,797**	**$170,454,514**	**$185,175,292**	**($14,720,777)**	**92.1%**

* Shows four months ended 30-Sep-09