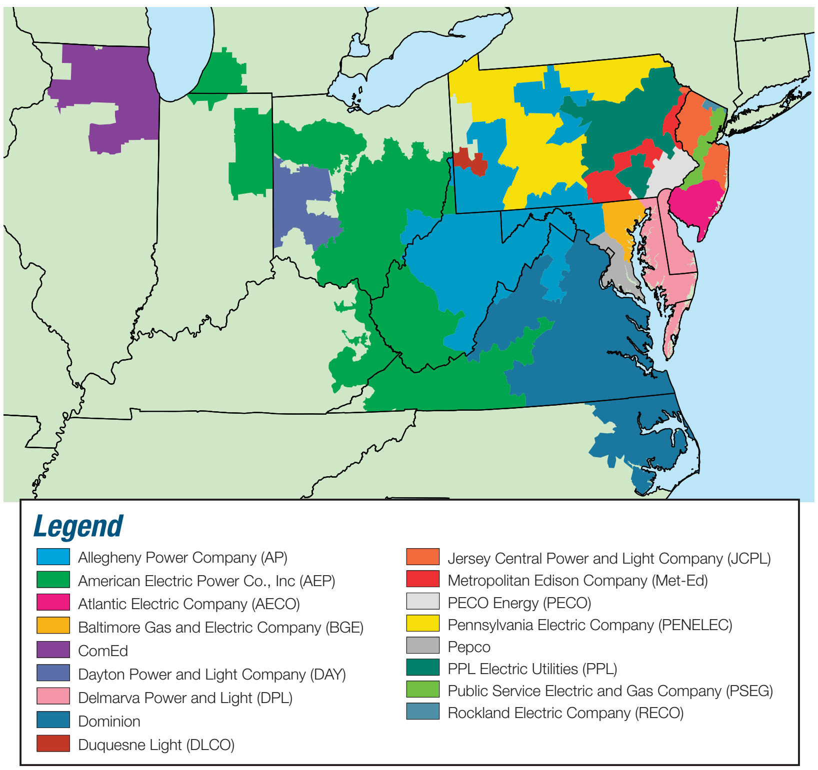
APPENDIX A – PJM GEOGRAPHY

During 2007, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

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



Analysis of 2007 market results requires comparison to 2006 and certain other prior years. During 2006 and 2007 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

- Phase 1 (2004). The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

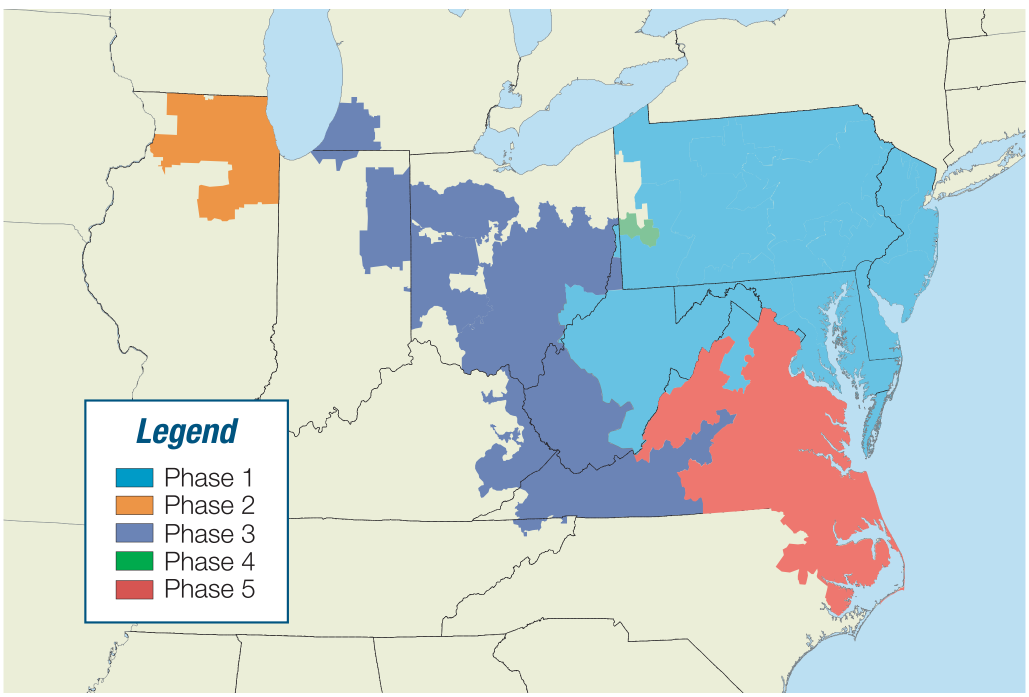
- Phase 2 (2004). The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- Phase 3 (2004). The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- Phase 4 (2005). The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- Phase 5 (2005). The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

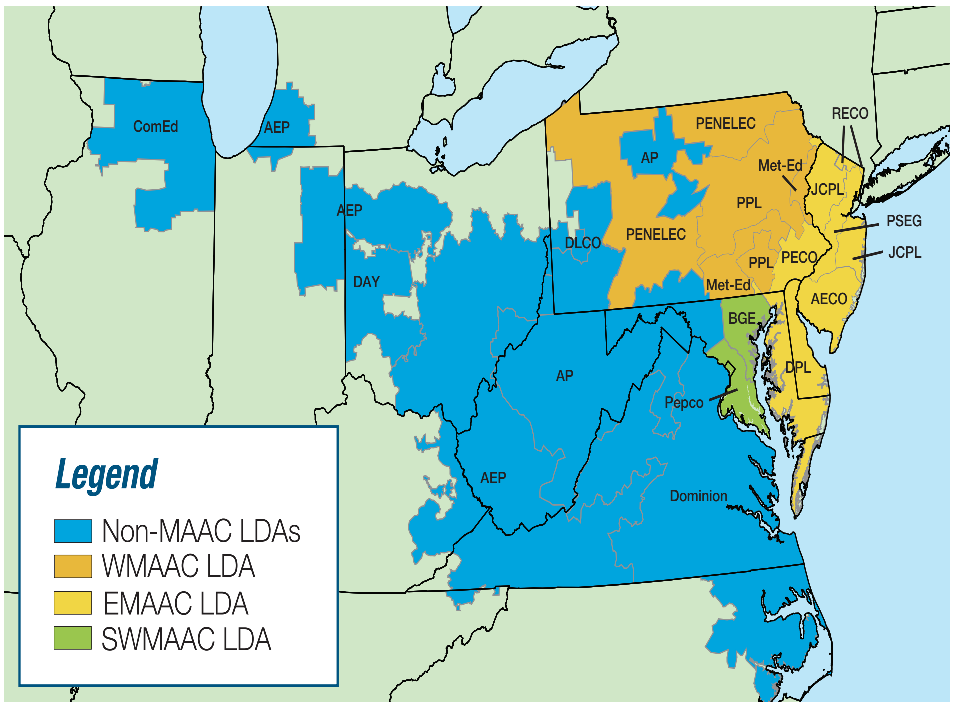
Figure A-2 PJM integration phases



4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

A locational deliverability area (LDA) is a geographic area within the PJM Control Area that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[5]

Figure A-3 PJM locational deliverability areas

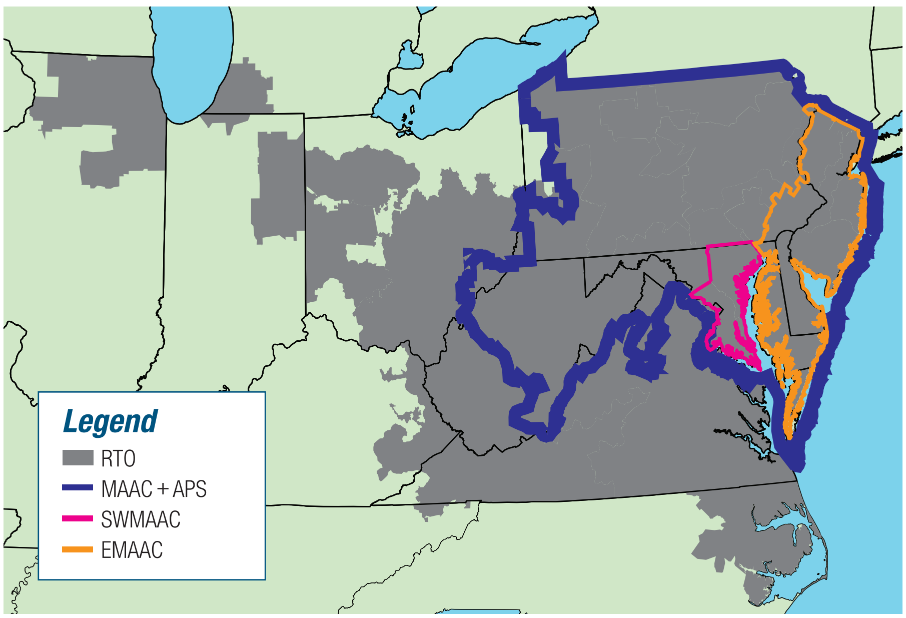


5 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 1, 2007).

In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 base auctions, the markets were RTO, EMAAC and SWMAAC. For the 2009/2010 base auction, the markets were RTO, MAAC+APS (Allegheny Power System) and SWMAAC. These RPM Auction markets are shown in Figure A-4.

Figure A-4 PJM RPM locational deliverability area markets



APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, “Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities”
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Credit Markets
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Inclusion of marginal loss component in LMP

APPENDIX C – ENERGY MARKET

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2003 to 2007.[1] The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY control zones during 2004 and the DLCO and Dominion control zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

In 2003, the most frequently occurring load interval was 35 GWh to 40 GWh at 31.3 percent of the hours, while load was less than 35 GWh for 36.3 percent of the hours.

The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY control zones. The most frequently occurring load interval was 35 GWh to 40 GWh at 15.8 percent of the hours. The next most frequently occurring interval was 40 GWh to 45 GWh at 14.9 percent of the hours. Load was less than 60 GWh for 74.8 percent of the time, less than 70 GWh for 92.8 percent of the time and less than 90 GWh for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion control zones. The most frequently occurring load interval was 75 GWh to 80 GWh at 16.1 percent of the hours. The next most frequently occurring interval was 65 GWh to 70 GWh at 13.4 percent of the hours. Load was less than 85 GWh for 72.9 percent of the time, less than 100 GWh for 88.2 percent of the time and less than 130 GWh for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.1 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 70.9 percent of the hours, less than 100 GWh for 91.5 percent of the hours and less than 130 GWh for all but 50 hours.

During 2007, the most frequently occurring load interval was 80 GWh to 85 GWh at 15.3 percent of the hours. The next most frequently occurring interval was 75 GWh to 80 GWh at 14.0 percent of the hours. Load was less than 85 GWh for 62.6 percent of the hours, less than 100 GWh for 88.8 percent of the hours and less than 130 GWh for all but 15 hours.

1 The definitions of load are discussed in the *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions."

2 See the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

The peak demand for 2007 was 139,428 MW on August 8, 2007. It was 3.6 percent lower than the 2006 peak demand of 144,644 MW on August 2, 2006.[3]

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	100	1.14%	15	0.17%	0	0.00%	0	0.00%	0	0.00%
25 to 30	1,193	14.76%	280	3.36%	0	0.00%	0	0.00%	0	0.00%
30 to 35	1,887	36.30%	697	11.29%	0	0.00%	0	0.00%	0	0.00%
35 to 40	2,738	67.56%	1,387	27.08%	0	0.00%	0	0.00%	0	0.00%
40 to 45	1,666	86.58%	1,311	42.01%	0	0.00%	0	0.00%	0	0.00%
45 to 50	796	95.66%	1,150	55.10%	71	0.81%	2	0.02%	0	0.00%
50 to 55	284	98.90%	847	64.74%	286	4.08%	129	1.50%	79	0.90%
55 to 60	84	99.86%	885	74.82%	636	11.34%	504	7.25%	433	5.84%
60 to 65	12	100.00%	760	83.47%	843	20.96%	689	15.11%	637	13.12%
65 to 70	0	100.00%	821	92.82%	1,170	34.32%	967	26.15%	890	23.28%
70 to 75	0	100.00%	391	97.27%	1,089	46.75%	1,079	38.47%	878	33.30%
75 to 80	0	100.00%	157	99.06%	1,407	62.81%	1,501	55.61%	1,227	47.31%
80 to 85	0	100.00%	48	99.60%	887	72.93%	1,337	70.87%	1,338	62.58%
85 to 90	0	100.00%	26	99.90%	557	79.29%	943	81.63%	981	73.78%
90 to 95	0	100.00%	7	99.98%	453	84.46%	569	88.13%	741	82.24%
95 to 100	0	100.00%	2	100.00%	330	88.23%	295	91.50%	577	88.82%
100 to 105	0	100.00%	0	100.00%	308	91.75%	215	93.95%	382	93.18%
105 to 110	0	100.00%	0	100.00%	283	94.98%	161	95.79%	223	95.73%
110 to 115	0	100.00%	0	100.00%	169	96.91%	145	97.44%	179	97.77%
115 to 120	0	100.00%	0	100.00%	113	98.20%	102	98.61%	106	98.98%
120 to 125	0	100.00%	0	100.00%	93	99.26%	45	99.12%	43	99.47%
125 to 130	0	100.00%	0	100.00%	43	99.75%	27	99.43%	31	99.83%
130 to 135	0	100.00%	0	100.00%	22	100.00%	19	99.65%	12	99.97%
135 to 140	0	100.00%	0	100.00%	0	100.00%	19	99.86%	3	100.00%
> 140	0	100.00%	0	100.00%	0	100.00%	12	100.00%	0	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2007 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak

3 Peak-load data for 2007 are from PJM's eMTR data.

load was about 24 percent higher than off-peak load in 2007. Average load during on-peak hours in 2007 was 3.1 percent higher than in 2006. Off-peak load in 2007 was 2.4 percent higher than in 2006.[4] (See Table C-3.)

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2007

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,268	32,344	1.28	24,728	31,081	1.26	4,091	4,388	1.07
1999	26,453	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,817	40,362	1.27	30,654	38,378	1.25	6,060	7,419	1.22
2003	33,595	41,755	1.24	32,971	40,802	1.24	5,546	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04

Table C-3 Multiyear change in load: Calendar years 1998 to 2007

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.7%	17.7%	(0.8%)	16.0%	16.0%	0.0%	43.4%	52.9%	6.1%
2003	5.6%	3.5%	(2.4%)	7.6%	6.3%	(0.8%)	(8.5%)	(26.9%)	(19.7%)
2004	32.9%	34.2%	1.6%	30.5%	38.7%	5.6%	95.5%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	0.0%	(10.9%)	(16.9%)	(6.7%)
2007	2.4%	3.1%	0.8%	2.1%	4.3%	1.7%	1.3%	(5.8%)	(7.1%)

4 The increase in on-peak median load for 2006 was incorrectly reported as 3.2 percent in the *2006 State of the Market Report* rather than the 2.8 percent shown here.

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the PJM Market Monitoring Unit (MMU) examines three measures: simple average LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Simple average LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.[5]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2003 to 2007. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly PJM LMP was within a given $10-per-MWh price interval and lower than $300 per MWh, or within a given $100-per-MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

In 2003, LMP was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours, less than $100 per MWh for 87.4 percent of the hours and LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours). In 2006, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (22.4 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (21.0 percent of the hours). In 2007, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (17.9 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (16.8 percent of the hours). In 2007, LMP was $60 per MWh or less for 60.7 percent of the hours and was $100 per MWh or less for 91.0 percent of the hours. LMP was more than $200 per MWh for 35 hours (0.4 percent of the hours).

5 See the *2007 State of the Market Report*, Volume II, Appendix H, "Calculating Locational Marginal Price."

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	241	2.75%	173	1.97%	142	1.62%	85	0.97%	56	0.64%
$10 to $20	2,083	26.53%	712	10.08%	259	4.58%	247	3.79%	185	2.75%
$20 to $30	1,957	48.87%	1,900	31.71%	1,290	19.30%	1,958	26.14%	1,571	20.68%
$30 to $40	1,102	61.45%	1,928	53.65%	1,793	39.77%	1,840	47.15%	1,470	37.47%
$40 to $50	1,043	73.36%	1,445	70.10%	1,172	53.15%	1,405	63.18%	1,108	50.11%
$50 to $60	812	82.63%	994	81.42%	877	63.16%	1,040	75.06%	931	60.74%
$60 to $70	532	88.70%	668	89.03%	730	71.50%	662	82.61%	827	70.18%
$70 to $80	380	93.04%	445	94.09%	568	77.98%	479	88.08%	726	78.47%
$80 to $90	255	95.95%	270	97.17%	453	83.15%	347	92.04%	646	85.84%
$90 to $100	152	97.68%	117	98.50%	374	87.42%	230	94.67%	451	90.99%
$100 to $110	75	98.54%	72	99.32%	297	90.81%	162	96.52%	240	93.73%
$110 to $120	52	99.13%	25	99.60%	208	93.18%	95	97.60%	178	95.76%
$120 to $130	28	99.45%	14	99.76%	159	95.00%	61	98.30%	110	97.02%
$130 to $140	23	99.71%	10	99.87%	110	96.26%	46	98.82%	76	97.89%
$140 to $150	14	99.87%	6	99.94%	94	97.33%	27	99.13%	53	98.49%
$150 to $160	5	99.93%	3	99.98%	53	97.93%	16	99.32%	26	98.79%
$160 to $170	1	99.94%	1	99.99%	57	98.58%	11	99.44%	29	99.12%
$170 to $180	1	99.95%	0	99.99%	51	99.17%	6	99.51%	18	99.33%
$180 to $190	2	99.98%	1	100.00%	22	99.42%	3	99.54%	9	99.43%
$190 to $200	1	99.99%	0	100.00%	16	99.60%	5	99.60%	15	99.60%
$200 to $210	0	99.99%	0	100.00%	12	99.74%	3	99.63%	6	99.67%
$210 to $220	1	100.00%	0	100.00%	10	99.85%	7	99.71%	4	99.71%
$220 to $230	0	100.00%	0	100.00%	5	99.91%	1	99.73%	4	99.76%
$230 to $240	0	100.00%	0	100.00%	1	99.92%	1	99.74%	2	99.78%
$240 to $250	0	100.00%	0	100.00%	1	99.93%	1	99.75%	5	99.84%
$250 to $260	0	100.00%	0	100.00%	3	99.97%	1	99.76%	2	99.86%
$260 to $270	0	100.00%	0	100.00%	2	99.99%	0	99.76%	4	99.91%
$270 to $280	0	100.00%	0	100.00%	0	99.99%	3	99.79%	0	99.91%
$280 to $290	0	100.00%	0	100.00%	1	100.00%	1	99.81%	0	99.91%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	0	99.81%	0	99.91%
$300 to $400	0	100.00%	0	100.00%	0	100.00%	11	99.93%	2	99.93%
$400 to $500	0	100.00%	0	100.00%	0	100.00%	2	99.95%	4	99.98%
$500 to $600	0	100.00%	0	100.00%	0	100.00%	1	99.97%	1	99.99%
$600 to $700	0	100.00%	0	100.00%	0	100.00%	1	99.98%	1	100.00%
> $700	0	100.00%	0	100.00%	0	100.00%	2	100.00%	0	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2006 to 2007

Table C-5 shows load-weighted, average LMP for 2006 and 2007 during off-peak and on-peak periods. In 2007, the on-peak, load-weighted LMP was 53 percent higher than the off-peak LMP, while in 2006, it was 55 percent higher. On-peak, load-weighted, average LMP in 2007 was 14.7 percent higher than in 2006. Off-peak, load-weighted LMP in 2007 was 16.6 percent higher than in 2006. The on-peak median LMP was higher in 2007 than in 2006 by 26.4 percent; off-peak median LMP was higher in 2007 than in 2006 by 12.8 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 21.5 percent higher in 2007 than in 2006 during off-peak hours and was 12.1 percent lower during on-peak hours. Since the average was above the median during on-peak and off-peak hours, both showed a positive skewness. The average was, however, proportionately higher than the median in 2007 as compared to 2006 during off-peak periods (27.8 percent in 2007 compared to 23.6 percent in 2006). The differences reflect larger positive skewness in the off-peak hours.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006			2007			Difference 2006 to 2007		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$41.53	$64.46	1.55	$48.43	$73.91	1.53	16.6%	14.7%	(1.3%)
Median	$33.59	$53.96	1.61	$37.89	$68.23	1.80	12.8%	26.4%	11.8%
Standard deviation	$24.03	$44.45	1.85	$29.20	$39.07	1.34	21.5%	(12.1%)	(27.6%)

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up about 80 percent of marginal cost on average for marginal units, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in fuel cost between different time periods of interest, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs on a common fuel-cost basis.[6]

Table C-6 and Table C-7 show the real-time, load-weighted, average LMP and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2007 for on-peak and off-peak hours. During on-peak hours, the real-time, fuel-cost-adjusted, load-weighted, average LMP in 2007 increased by 16.1 percent over the real-time, load-weighted LMP in 2006. The real-time, fuel-cost-adjusted, load-weighted LMP in 2007 increased by 20.9 percent in the off-peak hours compared to the real-time, load-weighted LMP in 2006.

6 See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table C-6 On-peak PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Year-over-year method

	2005	2006	2007
Load-weighted LMP	$78.04	$64.46	$73.91
Fuel-cost-adjusted, load-weighted LMP	NA	$72.37	$74.86
Year-over-year comparison	NA	(7.3%)	16.1%

Table C-7 Off-peak PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Year-over-year method

	2005	2006	2007
Load-weighted LMP	$47.69	$41.53	$48.43
Fuel-cost-adjusted, load-weighted LMP	NA	$46.05	$50.20
Year-over-year comparison	NA	(3.4%)	20.9%

PJM Real-Time, Load-Weighted LMP during Constrained Hours

Table C-8 shows that the PJM load-weighted, average LMP during constrained hours was 12.0 percent higher in 2007 than it had been in 2006.[7] The load-weighted, median LMP during constrained hours was 18.9 percent higher in 2007 than in 2006 and the standard deviation was 4.8 percent lower in 2007 than in 2006.

Table C-8 PJM load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference
Average	$57.62	$64.54	12.0%
Median	$48.34	$57.49	18.9%
Standard deviation	$40.01	$38.09	(4.8%)

Table C-9 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2006 and 2007. In 2007, load-weighted, average LMP during constrained hours was 35.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2006 was 61.1 percent.

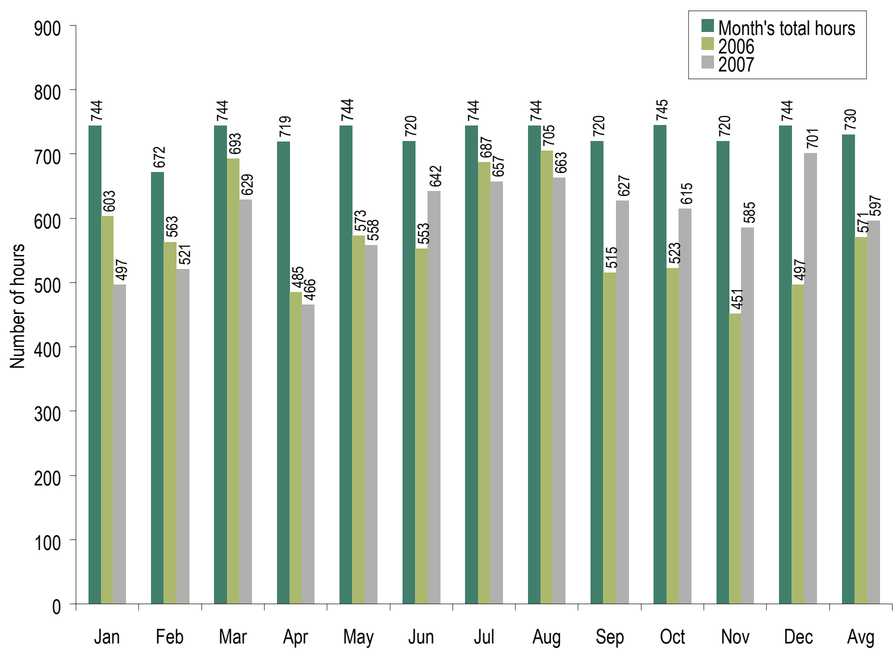
Table C-9 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2006 to 2007

	2006			2007		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$35.76	$57.62	61.1%	$47.82	$64.54	35.0%
Median	$29.67	$48.34	62.9%	$40.15	$57.49	43.2%
Standard deviation	$18.43	$40.01	117.1%	$26.78	$38.09	42.2%

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. Since the *2006 State of the Market Report,* in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency has been measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Figure C-1 shows the number of hours and the number of constrained hours during each month in 2006 and 2007. There were 7,161 constrained hours in 2007 and 6,848 in 2006, an increase of approximately 4.6 percent. Figure C-1 also shows that the average number of constrained hours per month was slightly higher in 2007 than in 2006, with 597 per month in 2007 versus 571 per month in 2006.

Figure C-1 PJM real-time constrained hours: Calendar years 2006 to 2007



Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2007 were higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2007 can be seen by comparing Table C-4 and Table C-10. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the most frequently occurring price interval was the $20-per-MWh to $30-per-MWh interval with 17.9 percent of the hours in 2007. (See Table C-4.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $30-per-MWh to $40-per-MWh interval with 17.1 percent of the hours in 2007. (See Table C-10.) In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.4 percent of the hours), reaching a high for the year of $673.98 per MWh on August 8, 2007, during the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for one hour (0.0 percent of the hours) and reached a high for the year of $200.50 per MWh on August 8, 2007, during the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	131	1.50%	59	0.67%	47	0.54%	11	0.13%	3	0.03%
$10 to $20	1,530	18.96%	715	8.81%	162	2.39%	147	1.80%	88	1.04%
$20 to $30	1,846	40.03%	1,684	27.98%	1,022	14.05%	1,610	20.18%	1,291	15.78%
$30 to $40	1,635	58.70%	1,848	49.02%	1,753	34.06%	1,747	40.13%	1,495	32.84%
$40 to $50	1,384	74.50%	1,946	71.17%	1,382	49.84%	1,890	61.70%	1,221	46.78%
$50 to $60	1,004	85.96%	1,357	86.62%	1,102	62.42%	1,364	77.27%	1,266	61.23%
$60 to $70	554	92.28%	728	94.91%	812	71.69%	905	87.60%	1,301	76.08%
$70 to $80	318	95.91%	278	98.08%	686	79.52%	524	93.58%	939	86.80%
$80 to $90	157	97.71%	110	99.33%	524	85.50%	237	96.29%	504	92.56%
$90 to $100	95	98.79%	42	99.81%	388	89.93%	145	97.95%	264	95.57%
$100 to $110	41	99.26%	11	99.93%	263	92.93%	65	98.69%	155	97.34%
$110 to $120	21	99.50%	4	99.98%	207	95.30%	38	99.12%	104	98.53%
$120 to $130	22	99.75%	2	100.00%	151	97.02%	11	99.25%	59	99.20%
$130 to $140	7	99.83%	0	100.00%	102	98.18%	8	99.34%	33	99.58%
$140 to $150	5	99.89%	0	100.00%	64	98.92%	8	99.43%	13	99.73%
$150 to $160	10	100.00%	0	100.00%	46	99.44%	7	99.51%	8	99.82%
$160 to $170	0	100.00%	0	100.00%	27	99.75%	6	99.58%	7	99.90%
$170 to $180	0	100.00%	0	100.00%	11	99.87%	6	99.65%	3	99.93%
$180 to $190	0	100.00%	0	100.00%	8	99.97%	3	99.68%	4	99.98%
$190 to $200	0	100.00%	0	100.00%	1	99.98%	3	99.71%	1	99.99%
$200 to $210	0	100.00%	0	100.00%	2	100.00%	3	99.75%	1	100.00%
$210 to $220	0	100.00%	0	100.00%	0	100.00%	3	99.78%	0	100.00%
$220 to $230	0	100.00%	0	100.00%	0	100.00%	1	99.79%	0	100.00%
$230 to $240	0	100.00%	0	100.00%	0	100.00%	3	99.83%	0	100.00%
$240 to $250	0	100.00%	0	100.00%	0	100.00%	2	99.85%	0	100.00%
$250 to $260	0	100.00%	0	100.00%	0	100.00%	1	99.86%	0	100.00%
$260 to $270	0	100.00%	0	100.00%	0	100.00%	2	99.89%	0	100.00%
$270 to $280	0	100.00%	0	100.00%	0	100.00%	1	99.90%	0	100.00%
$280 to $290	0	100.00%	0	100.00%	0	100.00%	1	99.91%	0	100.00%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	1	99.92%	0	100.00%
>$300	0	100.00%	0	100.00%	0	100.00%	7	100.00%	0	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Simple Average LMP

Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2007. On-peak, day-ahead and real-time, average LMPs were 63 percent and 57 percent higher, respectively, than the corresponding off-peak average LMPs. Since the average was above the median in these markets, both showed a positive skewness. The average was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (8 percent and 28 percent compared to 4 percent and 14 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-2 and Figure C-3 show the difference between real-time and day-ahead LMP during calendar year 2007 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $2.54 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $3.22 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$42.33	$68.84	1.63	$45.55	$71.38	1.57	7.6%	3.7%	(3.7%)
Median	$37.10	$66.08	1.78	$35.50	$65.88	1.86	(4.3%)	(0.3%)	4.5%
Standard deviation	$18.21	$21.91	1.20	$27.65	$36.57	1.32	51.8%	66.9%	10.0%

Figure C-2 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2007

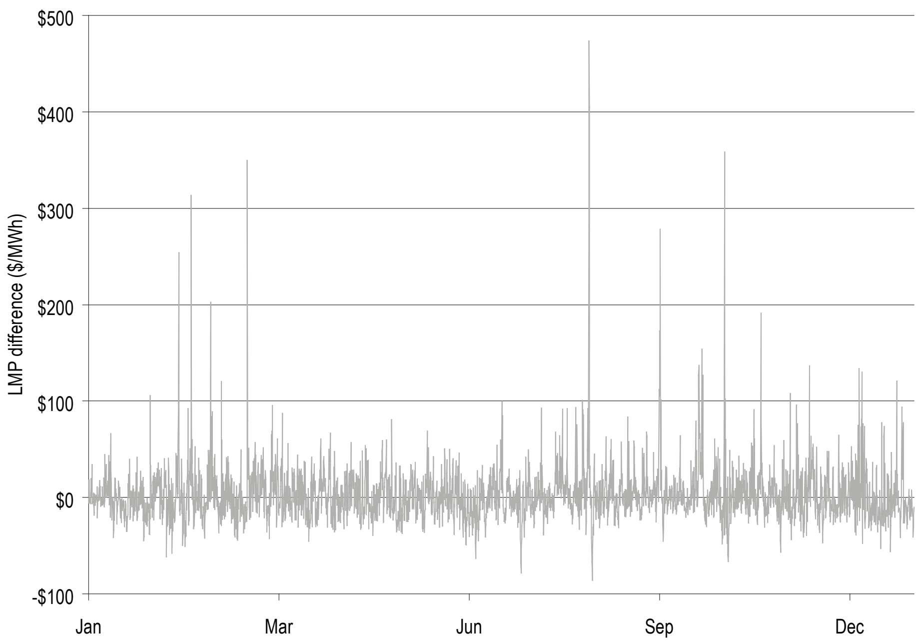
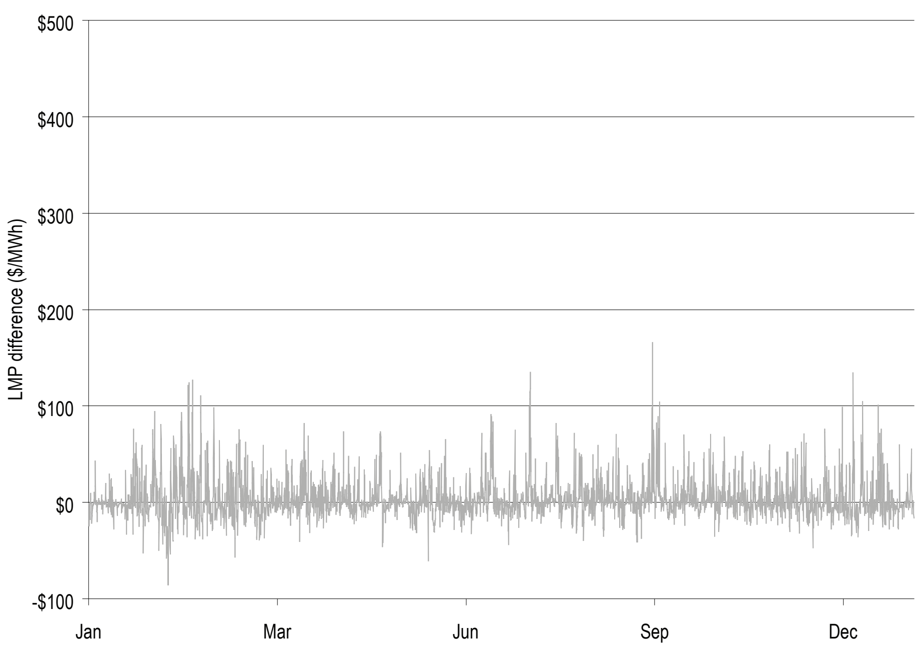


Figure C-3 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2007



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Simple Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2007. The zone with the maximum difference between on-peak real-time and day-ahead LMP was the BGE Control Zone with a day-ahead, on-peak, zonal LMP that was $4.20 lower than its real-time, on-peak, zonal LMP. The ComEd Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.15 lower than its day-ahead, on-peak, zonal LMP. (See Table C-12.) The BGE Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with day-ahead LMP that was $4.61 lower than real-time LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the ComEd Control Zone with a day-ahead LMP that was $0.81 lower than real-time LMP. (See Table C-13.)

Table C-12 On-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$78.04	$79.85	$1.81	2.27%
AEP	$59.45	$60.01	$0.56	0.93%
AP	$68.95	$71.22	$2.27	3.19%
BGE	$80.18	$84.38	$4.20	4.98%
ComEd	$59.55	$59.40	($0.15)	(0.25%)
DAY	$59.11	$60.00	$0.89	1.48%
DLCO	$57.04	$59.05	$2.01	3.40%
Dominion	$76.66	$79.08	$2.42	3.06%
DPL	$76.17	$78.11	$1.94	2.48%
JCPL	$78.54	$80.42	$1.88	2.34%
Met-Ed	$76.43	$79.43	$3.00	3.78%
PECO	$75.22	$75.90	$0.68	0.90%
PENELEC	$66.54	$68.54	$2.00	2.92%
Pepco	$81.03	$84.29	$3.26	3.87%
PPL	$74.03	$75.67	$1.64	2.17%
PSEG	$79.41	$81.11	$1.70	2.10%
RECO	$78.83	$80.49	$1.66	2.06%

Table C-13 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$49.80	$52.09	$2.29	4.40%
AEP	$33.42	$34.81	$1.39	3.99%
AP	$42.61	$45.45	$2.84	6.25%
BGE	$52.47	$57.08	$4.61	8.08%
ComEd	$32.97	$33.78	$0.81	2.40%
DAY	$33.25	$34.68	$1.43	4.12%
DLCO	$32.16	$30.75	($1.41)	(4.59%)
Dominion	$51.88	$55.99	$4.11	7.34%
DPL	$49.56	$51.97	$2.41	4.64%
JCPL	$49.79	$52.94	$3.15	5.95%
Met-Ed	$48.70	$51.62	$2.92	5.66%
PECO	$49.06	$51.01	$1.95	3.82%
PENELEC	$41.13	$42.82	$1.69	3.95%
Pepco	$53.72	$58.16	$4.44	7.63%
PPL	$47.77	$50.12	$2.35	4.69%
PSEG	$50.45	$52.67	$2.22	4.21%
RECO	$49.89	$51.20	$1.31	2.56%

PJM Day-Ahead and Real-Time, Simple Average LMP during Constrained Hours

Figure C-4 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets, and the total number of hours in each month for 2007. Overall, there were 7,161 constrained hours in the Real-Time Energy Market and 8,757 constrained hours in the Day-Ahead Energy Market. Figure C-4 shows that in every month of calendar year 2007 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 22.3 percent more constrained hours than the Real-Time Energy Market.

Figure C-4 PJM day-ahead and real-time, market-constrained hours: Calendar year 2007

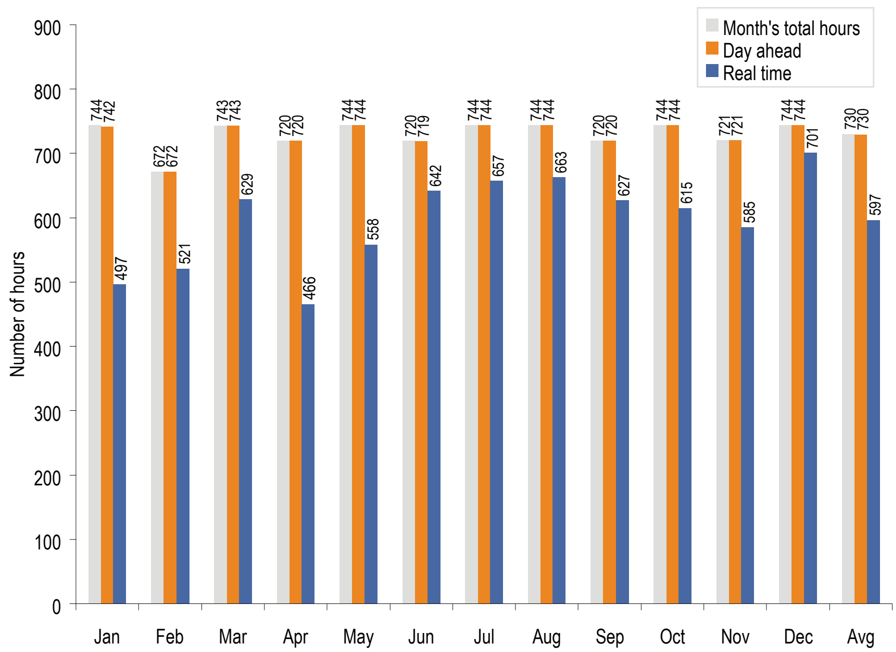


Table C-14 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 7.9 percent higher than average LMP during unconstrained hours.[8] In the Real-Time Energy Market, average LMP during constrained hours was 33.2 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 10.3 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 10.7 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

8 This comparison is of limited usefulness as there were only three, day-ahead unconstrained hours.

Table C-14 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2007

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$50.68	$54.68	7.9%	$45.28	$60.32	33.2%
Median	$64.50	$52.34	(18.9%)	$37.02	$52.49	41.8%
Standard deviation	$25.49	$23.99	(5.9%)	$25.82	$35.70	38.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was $0.01 (0.0 percent) higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was $3.99 (7.3 percent) lower although these comparisons are of limited usefulness as there were only three unconstrained hours in the Day-Ahead Energy Market.[9] In the Real-Time Energy Market, average LMP during constrained hours was 4.8 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 21.4 percent lower.

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[10] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[11] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

9 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

10 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).

11 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.[12]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.1%	0.4	0.1%	0.4	0.0%	0.1	0.0%	0.2	0.0%
Feb	0.7	0.1%	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.8	0.1%
Mar	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.7	0.1%	0.9	0.1%
Apr	0.6	0.1%	0.3	0.0%	0.4	0.0%	0.2	0.0%	0.2	0.0%
May	0.3	0.0%	0.6	0.1%	0.2	0.0%	0.1	0.0%	0.2	0.0%
Jun	0.7	0.1%	1.1	0.2%	0.4	0.0%	0.7	0.1%	0.8	0.1%
Jul	1.4	0.3%	2.6	0.4%	0.9	0.1%	4.1	0.4%	0.6	0.1%
Aug	2.1	0.4%	3.0	0.4%	1.1	0.1%	4.7	0.5%	1.0	0.1%
Sep	1.1	0.2%	3.1	0.4%	0.2	0.0%	0.6	0.1%	0.2	0.0%
Oct	0.9	0.2%	0.6	0.1%	0.3	0.0%	0.3	0.0%	0.8	0.1%
Nov	0.2	0.0%	0.5	0.1%	0.2	0.0%	0.3	0.0%	0.0	0.0%
Dec	0.1	0.0%	0.5	0.1%	0.7	0.1%	0.7	0.0%	0.1	0.0%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	37	0.1%	51	0.1%	87	0.1%	4	0.0%	23	0.0%
Feb	27	0.1%	68	0.1%	75	0.1%	6	0.0%	57	0.1%
Mar	4	0.0%	48	0.1%	58	0.1%	51	0.1%	86	0.1%
Apr	38	0.1%	41	0.1%	34	0.0%	31	0.0%	11	0.0%
May	52	0.1%	52	0.1%	14	0.0%	22	0.0%	38	0.0%
Jun	69	0.2%	49	0.1%	28	0.0%	164	0.2%	28	0.0%
Jul	132	0.3%	243	0.4%	52	0.0%	518	0.5%	45	0.0%
Aug	148	0.3%	348	0.5%	63	0.1%	398	0.4%	58	0.1%
Sep	139	0.3%	221	0.4%	13	0.0%	51	0.1%	14	0.0%
Oct	100	0.2%	34	0.0%	16	0.0%	27	0.0%	77	0.1%
Nov	21	0.1%	28	0.0%	26	0.0%	15	0.0%	4	0.0%
Dec	25	0.1%	35	0.0%	48	0.0%	40	0.0%	4	0.0%

12 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table C-17 Average real-time, offer-capped units: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.5	0.3%	2.7	0.4%	2.5	0.3%	1.9	0.2%	1.2	0.1%
Feb	1.5	0.3%	0.7	0.1%	1.3	0.1%	2.1	0.2%	4.2	0.4%
Mar	0.5	0.1%	0.8	0.1%	1.4	0.2%	2.3	0.2%	1.9	0.2%
Apr	0.8	0.1%	1.8	0.3%	1.2	0.1%	1.5	0.2%	1.3	0.1%
May	1.6	0.3%	5.9	0.8%	0.8	0.1%	3.4	0.3%	1.9	0.2%
Jun	2.9	0.5%	3.9	0.5%	10.0	1.0%	2.5	0.3%	6.0	0.6%
Jul	3.3	0.6%	4.7	0.7%	13.9	1.4%	8.6	0.9%	4.4	0.4%
Aug	6.3	1.1%	6.3	0.9%	13.7	1.4%	9.5	1.0%	9.6	0.9%
Sep	3.7	0.7%	4.2	0.6%	7.9	0.8%	1.8	0.2%	5.5	0.5%
Oct	1.8	0.3%	1.1	0.1%	7.9	0.8%	1.7	0.2%	5.0	0.5%
Nov	1.0	0.2%	1.1	0.1%	3.3	0.3%	1.1	0.1%	2.9	0.3%
Dec	0.8	0.1%	3.3	0.4%	4.4	0.4%	1.0	0.0%	4.7	0.5%

Table C-18 Average real-time, offer-capped MW: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	86.8	0.2%	175.0	0.4%	208.9	0.3%	42.1	0.1%	50.0	0.1%
Feb	74.2	0.2%	86.8	0.2%	144.9	0.2%	67.1	0.1%	125.0	0.1%
Mar	44.0	0.1%	76.2	0.2%	74.2	0.1%	87.6	0.1%	142.3	0.2%
Apr	28.8	0.1%	115.2	0.3%	58.8	0.1%	75.3	0.1%	48.4	0.1%
May	101.2	0.3%	257.1	0.5%	77.9	0.1%	135.6	0.2%	67.7	0.1%
Jun	110.0	0.3%	166.8	0.3%	652.1	0.7%	160.1	0.2%	190.4	0.2%
Jul	251.6	0.6%	331.9	0.6%	818.8	0.9%	505.8	0.5%	160.0	0.2%
Aug	293.9	0.7%	450.4	0.8%	908.4	1.0%	517.8	0.6%	314.0	0.3%
Sep	240.8	0.7%	268.5	0.5%	476.9	0.6%	68.7	0.1%	218.3	0.3%
Oct	96.0	0.3%	77.2	0.1%	337.5	0.5%	49.4	0.1%	153.2	0.2%
Nov	53.5	0.2%	110.4	0.2%	129.4	0.2%	30.5	0.0%	104.2	0.1%
Dec	44.0	0.1%	202.0	0.3%	155.5	0.2%	11.5	0.0%	146.3	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-22 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2003 through 2006.

Table C-19 Offer-capped unit statistics: Calendar year 2003

	2003 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	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	0	1
80% and < 90%	0	1	0	0	1	7
75% and < 80%	1	0	0	3	3	2
70% and < 75%	0	0	0	1	1	2
60% and < 70%	0	0	0	2	3	11
50% and < 60%	0	0	0	3	2	8
25% and < 50%	4	3	2	0	3	34
10% and < 25%	1	0	0	2	11	38

Table C-20 Offer-capped unit statistics: Calendar year 2004

	2004 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	1	1	5	3	5
80% and < 90%	3	0	0	5	6	10
75% and < 80%	1	0	4	0	1	7
70% and < 75%	0	1	0	0	1	7
60% and < 70%	1	1	0	0	0	7
50% and < 60%	0	0	0	1	1	13
25% and < 50%	1	1	1	3	6	32
10% and < 25%	2	0	2	3	16	38

Table C-21 Offer-capped unit statistics: Calendar year 2005[13]

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2005 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%	12	1	0	1	2	2
80% and < 90%	7	6	0	6	7	10
75% and < 80%	0	1	3	3	8	3
70% and < 75%	0	0	1	2	4	4
60% and < 70%	1	0	3	2	8	9
50% and < 60%	0	0	2	0	2	10
25% and < 50%	2	9	1	3	10	49
10% and < 25%	0	0	1	0	6	33

Table C-22 Offer-capped unit statistics: Calendar year 2006

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2006 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%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

13 Data quality improvements have caused values in this table to vary slightly from previously published results for 2005.

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security-constrained nodal pricing, well-designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

NYISO Issues

If interface prices were defined and established in a comparable manner by PJM and the New York Independent System Operator (NYISO), if identical rules governed external transactions in PJM and NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is relevant in considering the observed relationship between interface prices and inter-ISO power flows, and those price differentials.

There are institutional differences between PJM and NYISO markets that are relevant to observed differences in border prices.[1] NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[2] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of NYISO's RTC timing, market participants must submit bids or offers by no less than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, market participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[3] The duration of the requested transaction can vary from 15 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit an associated

1 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

2 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed February 28, 2008) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

3 See PJM. "Manual 11: Scheduling Operations" (September 28, 2007) (Accessed February 14, 2008) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

price. Transactions are accepted, with virtually no lag, in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Energy Market. As in NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid North American Electric Reliability Council (NERC) Tag, an Open Access Same-Time Information System (OASIS) reservation, a PJM schedule and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

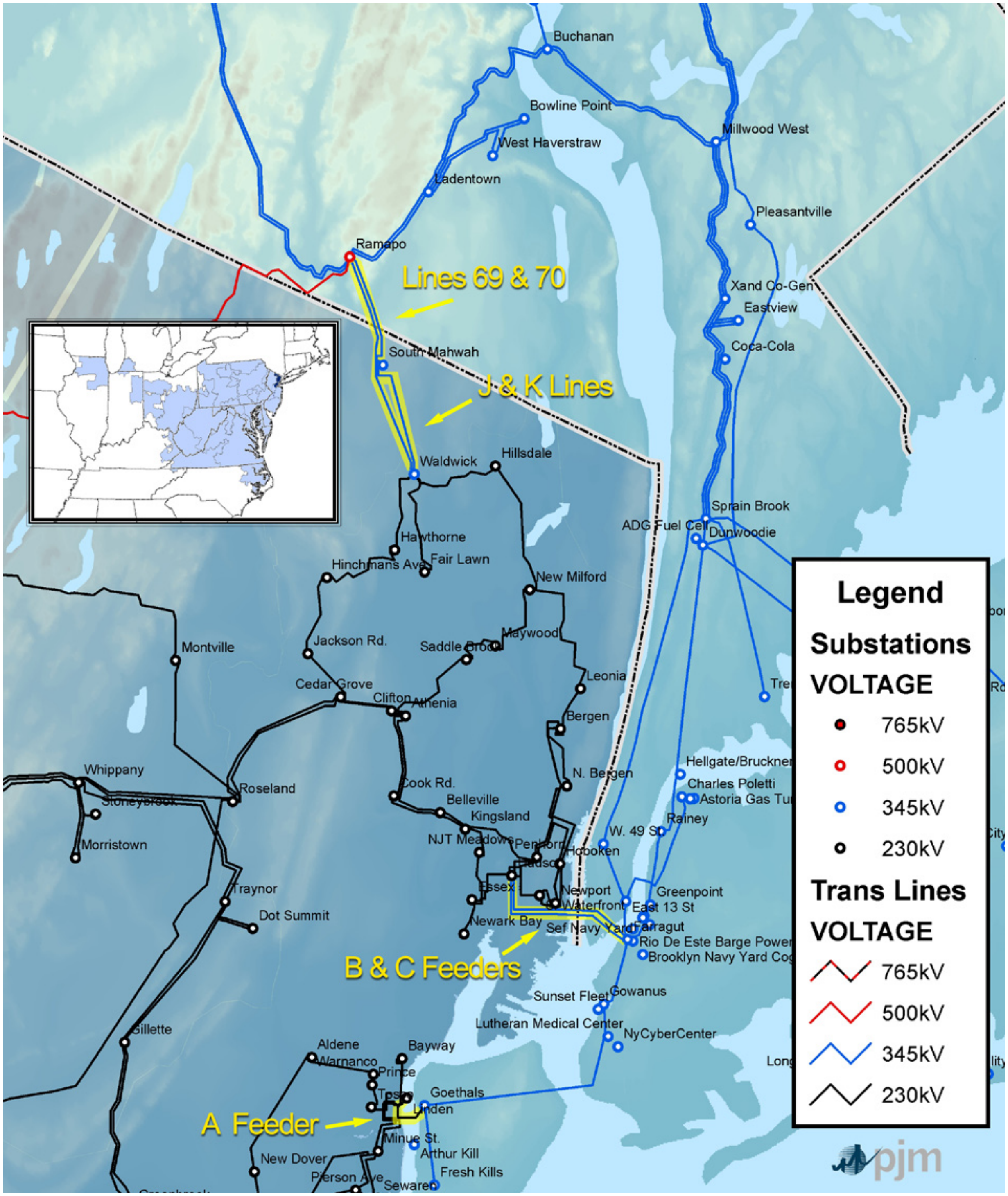
Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the United States Federal Energy Regulatory Commission (FERC) in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[4] In July 2005, the protocol was implemented.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had underdelivered on the agreements and asked the FERC to resolve the issue.

4 111 FERC ¶ 61,228 (2005).

Figure D-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[5] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion charges associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the protocol, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2007, PSE&G's FTR credits were equal to its congestion charges. (Credits had been $0.4 million less than charges in 2006.)[6] Under the protocol, Con Edison receives credits for its elections under the 400 MW contract from a pool containing any excess congestion revenue after FTRs are funded. In 2007, Con Edison's congestion credits equaled its day-ahead congestion charges. However, Con Edison had substantial negative day-ahead congestion charges with the result that Con Edison's total credits exceeded its congestion charges by approximately $1.7 million. (Credits had been $0.7 million less than charges in 2006.) Table D-1 shows the monthly details for both PSE&G and Con Edison. The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[7]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were about $1.7 million in 2007. The parties should address this issue.

5 111 FERC ¶ 61,228 (2005).

6 See the *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," Table D-1, "Con Edison and PSE&G wheel settlements data: Calendar year 2006" (March 8, 2007), pp. 376-377.

7 PJM Interconnection, L.L.C., Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 < www.pjm.com/documents/downloads/agreements/20050701-attachment-iv-operating-protocol.pdf > (330 KB).

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits based on the difference between day-ahead and real-time prices. The real-time election differed from the day-ahead schedule in 13 percent of the hours in 2007.

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2007

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion charge	($107,716.00)		($107,716.00)	($161,574.00)		($161,574.00)
	Congestion credit			$73,200.00			($161,574.00)
	Previous month(s) adj.						
	Net charge			($180,916.00)			$0.00
February	Congestion charge	($257,886.98)	$1,506.57	($256,380.41)	($373,892.68)		($373,892.68)
	Congestion credit			$86,079.72			($373,892.68)
	Previous month(s) adj.						
	Net charge			($342,460.13)			$0.00
March	Congestion charge	$186,039.36	($1,569.47)	$184,469.89	297,540.00		$297,540.00
	Congestion credit			$197,083.36			$297,540.00
	Previous month(s) adj.						
	Net charge			($12,613.47)			$0.00
April	Congestion charge	$113,935.89	$796.37	$114,732.26	$291,906.00		$291,906.00
	Congestion credit			$127,538.49			$291,906.00
	Previous month(s) adj.						
	Net charge			($12,806.23)			$0.00
May	Congestion charge	$436,372.00	($18,781.50)	$417,590.50	$654,558.00		$654,558.00
	Congestion credit			$448,020.00			$654,558.00
	Previous month(s) adj.			$121,038.35			
	Net charge			($151,467.85)			$0.00
June	Congestion charge	$245,449.00	($23,080.14)	$222,368.86	$370,284.00		$370,284.00
	Congestion credit			$103,771.00			$59,898.00
	Previous month(s) adj.						
	Net charge			$118,597.86			$310,386.00
July	Congestion charge	($24,207.00)		($24,207.00)	($37,824.00)		($37,824.00)
	Congestion credit			$214,876.00			$272,562.00
	Previous month(s) adj.						
	Net charge			($239,083.00)			($310,386.00)

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2007, continued

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion charge	$142,676.00		$142,676.00	$214,014.00		$214,014.00
	Congestion credit			$167,740.00			$214,014.00
	Previous month(s) adj.						
	Net charge			($25,064.00)			$0.00
September	Congestion charge	$495,152.00	($371,969.39)	$123,182.61	$742,728.00		$742,728.00
	Congestion credit			$528,576.00			$742,728.00
	Previous month(s) adj.						
	Net charge			($405,393.39)			$0.00
October	Congestion charge	$144,010.00	($48,307.49)	$95,702.51	$221,568.00		$221,568.00
	Congestion credit			$145,441.10			$221,568.00
	Previous month(s) adj.						
	Net charge			($49,738.59)			$0.00
November	Congestion charge	$137,172.43	($2,160.32)	$135,012.11	$219,164.68		$219,164.68
	Congestion credit			$147,303.34			$219,164.68
	Previous month(s) adj.						
	Net charge			($12,291.23)			$0.00
December	Congestion charge	($265,350.18)		($265,350.18)	($398,025.02)		($398,025.02)
	Congestion credit			$81,113.13			($398,025.02)
	Previous month(s) adj.			($1,353.36)			($479.36)
	Net charge			($345,109.95)			$479.36
Total	Congestion charge	$1,245,646.52	($463,565.37)	$782,081.15	$2,040,446.98	$0.00	$2,040,446.98
	Congestion credit			$2,320,742.14			$2,040,446.98
	Adj.			$119,684.99			($479.36)
	Net charge			($1,658,345.98)			$479.36

APPENDIX E – CAPACITY MARKET

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation.

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM Control Area, replacing the Capacity Credit Market (CCM) Capacity Market design. This appendix explains certain key features of the RPM design in more detail.[1]

Demand

VRR Curves

Under RPM, PJM established variable resource requirement (VRR) curves for the PJM RTO and for each constrained locational deliverability area (LDA). The VRR curve is a demand curve based on three price-quantity points. The demand curve quantities are based on negative and positive adjustments to the reliability requirement. The demand curve prices are based on multipliers applied to the net cost of new entry (CONE). Net CONE is CONE minus the energy and ancillary service revenue offset (E&AS).[2]

The PJM reliability requirement represents the target level of reserves required to meet PJM reliability standards. It is the RTO peak-load forecast multiplied by the RTO forecast pool requirement (FPR) less the sum of any unforced capacity (UCAP) obligations served by fixed resource requirement (FRR) entities, all measured in UCAP.

Load Obligations

Participation by LSEs in the RPM for load served in PJM control zones is mandatory, except for those LSEs that have elected the FRR alternative.[3] Under RPM, each LSE that serves load in a PJM zone during the delivery year is responsible for paying a locational reliability charge equal to its daily unforced capacity obligation in the zone multiplied by the final zonal capacity price. LSEs may choose to hedge their locational reliability charge obligations by directly offering resources in the base residual auction (BRA) and second incremental auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the base residual auction.

1 This section relies upon the cited PJM manuals where additional detail may be found.

2 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 16 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

3 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 78 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

Base UCAP Obligations

A base RTO UCAP obligation is determined after the clearing of the BRA and is posted with the BRA results. The base RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA plus the forecast RTO interruptible load for reliability (ILR) obligation. Base zonal UCAP obligations are defined for each zone as an allocation of the RTO UCAP obligation based on zonal, peak-load forecasts and zonal ILR obligations. The zonal UCAP obligation is equal to the zonal, weather-normalized summer peak for the summer four years prior to the delivery year multiplied by the base zonal RPM scaling factor and the FPR plus the forecast zonal ILR obligation.

Final UCAP Obligation

The final RTO UCAP obligation is determined after the clearing of the second incremental auction (IA) and is posted with the second IA results. The final RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA and the second IA plus the forecast RTO ILR obligation. The final zonal UCAP obligation is equal to the base zonal UCAP obligation plus the RTO UCAP obligation satisfied in the second IA multiplied by the zone's percentage allocation of the obligation satisfied in the second IA.

LSE Daily UCAP Obligation

Obligation peak load is the peak-load value on which LSEs' UCAP obligations are based. The obligation, peak-load allocation for a zone is constant and effective for the entire delivery year. The daily UCAP obligation of an LSE in a zone/area equals the LSE's obligation peak load in the zone/area multiplied by the final zonal RPM scaling factor and the FPR.

Capacity Resources

Capacity resources may consist of generation resources, load management resources and qualifying transmission upgrades, all of which must meet PJM-specific criteria.[4] Generation resources may be located within or outside of PJM, but they must be committed to serving load within PJM and must pass tests regarding the capability of generation to serve load and to deliver energy.

Generation Resources

Generation resources may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Existing generation located within or outside PJM is eligible to be offered into RPM Auctions or traded bilaterally if it meets defined requirements.[5] Planned generation that is participating in PJM's Regional Transmission Expansion Planning (RTEP) Process is eligible to be offered into RPM Auctions if it meets defined requirements.

4 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 22 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

5 See PJM. "Manual 13: Emergency Operations," Revision 33 (Effective January 1, 2008) <http://www.pjm.com/contributions/pjm-manuals/pdf/m13.pdf> (461 KB).

Load Management Resources

Load management is the ability to reduce load upon request.[6] A load management resource is eligible to be offered as a demand resource (DR) or interruptible load for reliability (ILR). DR is a load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource-clearing price. ILR is a load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the close of the second incremental auction. DR and ILR resources must meet defined requirements.

Qualified Transmission Upgrades

A qualifying transmission upgrade may be offered into the BRA to increase import capability into a transmission-constrained LDA. Such transmission upgrades must meet the identified requirements.[7]

Obligations of Capacity Resources

The sale of a generating unit as a capacity resource within the PJM Control Area entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- Energy Recall Right. PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures. The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price.

- Day-Ahead Energy Market Offer Requirement. Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- Deliverability. To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency.[8] In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries through firm transmission service.

6 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 33 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

7 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 35 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

8 Deliverable per PJM. "Reliability Assurance Agreement," Schedule 10 (May 17, 2004), p. 52 <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[9]

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[10] The first step in this process is to determine the transmission import requirement into an LDA, called the capacity emergency transfer objective (CETO). This value, expressed in MW, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation due to insufficient import capability alone, of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the capacity emergency transfer limit (CETL), which is also expressed in MW. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, capacity-related transmission constraints may result in locational price differences in the RPM.[11] This will also trigger the planning of transmission upgrades under the RTEP Process.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

9 See PJM. “Reliability Assurance Agreement,” Schedule 12 (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

10 See PJM. “Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods,” Revision 10 (March 1, 2007), <http://www.pjm.com/contributions/pjm-manuals/pdf/m14b-redline.pdf >. PJM Manual 14B indicates that all “electrically cohesive load areas” are tested.

11 See PJM. “Manual 18: PJM Capacity Market,” Revision 0 (Effective June 1, 2007), p. 12, <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

Table E-1 NERC GADS cause codes deemed outside management control[12] (OMC)

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.
9250	Low Btu coal
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

12 See NERC. "Generator Availability Data System Data Reporting Instructions," Appendix K <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/apd-k_Outside_Plant_Management_Control.pdf> (161 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- CPS1. NERC requires that the first CPS measure provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it has met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), Section 3, "System Control," p. 12.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 32 (September 28, 2007), pp. 33-38.

3 See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), Section 4, pp. 47-51.

4 For more information about the definition and calculation of CPS, see PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), pp. 14-17. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

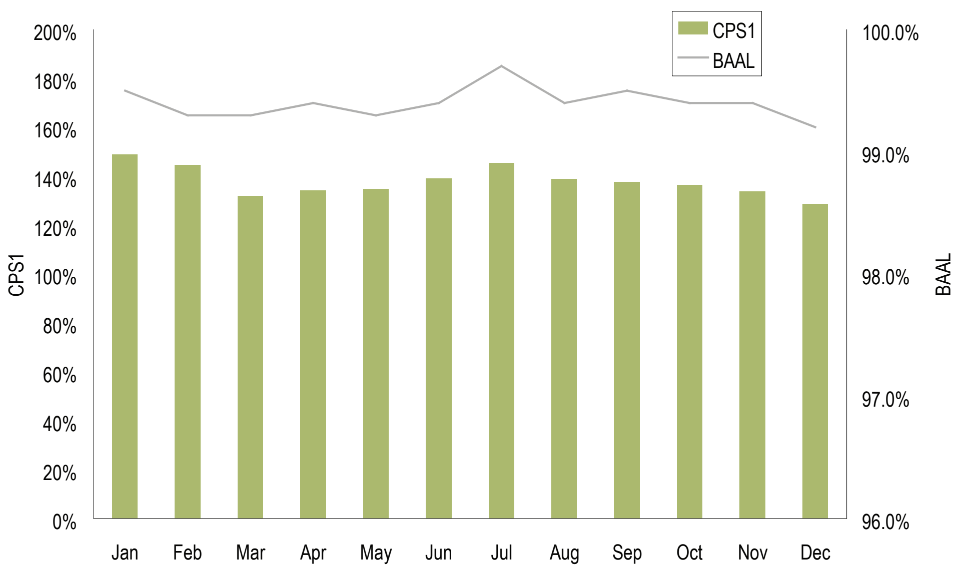
- CPS2. NERC also requires that the second CPS measure provide a measure of 10-minute ACE averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L10. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L10. From January 1, through January 31, 2007, the PJM Control Area's L10 standard was 284.3 MW. From February 1, through December 31, 2007, PJM's L10 standard was 286.1 MW.

- BAAL. Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 98 percent.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2007.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2007



5 See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), pp. 14-17.

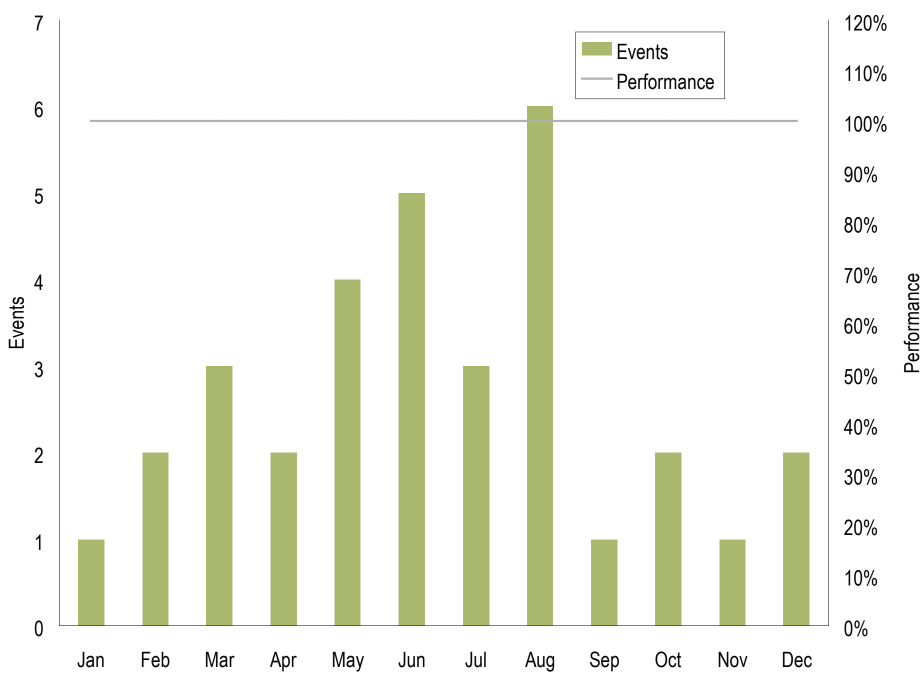
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing ACE and frequency on a monthly, running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 31 DCS events during calendar year 2007 and successfully recovered from all of them. All events were caused by a major unit's tripping. Recovery times ranged from two minutes to 15 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution for most of the events was to declare a 100 percent spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2007



6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) < ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-002-0.pdf > (61 KB).

Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. First, a theoretical, optimized energy dispatch is done based on current unit status and forecast LMP. Then the Market Operations Group creates a supply curve for regulation and for synchronized reserve of available units and their associated merit-order prices. Finally, the Market Operations Group assigns regulation and synchronized reserve to units in increasing order of price until the regulation MW and the synchronized reserve requirements are satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for three products (energy, regulation and synchronized reserve) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- Regulation Capacity. The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- Regulation Offers. All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation although during 2007 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- Regulation Offered and Eligible. Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation offer cost and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- Cleared Regulation. Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- Settled Regulation. Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;
- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and
- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	**Day-Ahead Congestion Price**	**Day-Ahead Load**	**Load Congestion Payments**	**Day-Ahead Generation**	**Generation Congestion Credits**	**Transmission Congestion Charges**
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	**Real-Time Congestion Price**	**Load Deviation**	**Load Congestion Payments**	**Generation Deviation**	**Generation Congestion Credits**	**Transmission Congestion Charges**
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission congestion charges accounting						
Balancing transmission congestion charges						$130
+Day-ahead transmission congestion charges						$1,500
=Total transmission congestion charges						$1,630
FTR Target Allocations						
Path	**Day-Ahead Path Price**	**FTR MW**	**FTR Target Allocations**	**Positive FTR Target Allocations**	**Negative FTR Target Allocations**	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion accounting						
Transmission congestion charges						$1,630
+Negative FTR target allocations						$250
=Total congestion charges						$1,880
Positive FTR target allocations				$2,000		
-FTR congestion credits				$1,880		
=Congestion credit deficiency				$120		
FTR payout ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual prorated MW =
(Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line).

The equation would then be solved for each request as follows:

ARR #1 prorated MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW; and

ARR #2 prorated MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW.

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability (150 MW • 0.50) + (100 MW • 0.25) = 100 MW.

ARR Credits

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market. For example, the FTR auction revenue is only $75 for the ARR on line A-D while the ARR target allocation is $150. The surplus FTR auction revenue from the other ARR paths is enough to cover the $75 deficiency and fulfill the ARR target allocation of $150.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR payout ratio = ARR credits / ARR target allocations = $400 / $400 = 100%						
Surplus ARR revenue = FTR auction revenue - ARR credits = $450 - $400 = $50						

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand exactly how average LMPs are calculated across time and across buses. This appendix explains how PJM calculates average LMP and load-weighted, average LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.[1]

Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus for every five-minute interval.

The system real-time, five-minute, average LMP is the load-weighted, average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and the five-minute load at each bus, divided by the sum of the five-minute loads across the buses equals the system load-weighted, average LMP for that five-minute interval.

In PJM, the real-time hourly LMP at a bus is equal to the simple average of each hour's 12 five-minute interval LMPs at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of each hour's 12 five-minute interval loads at that bus. This is termed the hourly integrated load at the bus. The hourly values for LMP and load are the basis of PJM's settlement calculations.

Day-Ahead Hourly LMP and Day-Ahead Hourly Load

Zonal, day-ahead hourly aggregate load is assigned to buses in the relevant zone using zonal distribution factors. Zonal distribution factors are calculated from historical real-time, bus-level load within the zone. The day-ahead LMP is calculated at every bus for every hour using these estimated nodal loads plus nodal load from decrement bids (DECs) and price-sensitive load and nodal supply from generation offers and increment offers (INCs). The result is a full set of day-ahead nodal LMPs and cleared, nodal loads. This measure of nodal, day-ahead load is used in system load-weighted, average LMP calculations. This is termed nodal, total day-ahead load here.

Load-Weighted, Average LMP

Real Time

The system real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

1 The unweighted, average LMP is also referred to as the simple average LMP.

The zonal real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, divided by the sum of the real-time hourly integrated loads for each load bus in that same zone.

The system real-time, load-weighted, average LMP for a day is equal to the product of the hourly integrated LMPs for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The zonal real-time, load-weighted, average LMP for a day is equal to the product of each of the hourly integrated LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that zone for the day.

The system real-time, load-weighted, average LMP for a year is equal to the product of the hourly integrated LMPs and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The zonal real-time load-weighted, average LMP for a year is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that zone for each hour in the year.

Day Ahead

The system day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly LMP at each load bus and the corresponding nodal, total day-ahead hourly load at each load bus in the system, divided by the sum of the nodal, total day-ahead hourly loads across the buses.

The zonal day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly bus LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a day is equal to the product of the hourly day-ahead LMPs for each load bus and the nodal, total hourly day-ahead load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the nodal, total hourly day-ahead loads for the system for the day.

The zonal day-ahead, load-weighted, average LMP for a day is equal to the product of each of the hourly day-ahead LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the day, and divided by the corresponding estimated total zonal load for the day. Again, the zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a year is equal to the product of the hourly LMPs and nodal, total hourly load for each load bus, summed across every hour of the year, divided by the sum of the nodal, total hourly bus loads at each load bus in the system for each hour in the year.

The zonal day-ahead, load-weighted, average LMP for a year is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the year, and divided by the total estimated zonal load for the years. Again, the zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

Equation H-1 LMP calculations

	i = 5-minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h = 1..24	y = 365 days = 8,760 hours = year d = 1..365
Bus average	LMP_{bi}	$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd} = \frac{\sum_{h=1}^{24} LMP_{bh}}{24}$	$LMP_{by} = \frac{\sum_{h=1}^{8760} LMP_{bh}}{8760}$
Bus load-weighted average			$lwLMP_{bd} = \frac{\sum_{h=1}^{24}(LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by} = \frac{\sum_{h=1}^{8760}(LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System average	$LMP_{si} = \frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh} = \frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd} = \frac{\sum_{h=1}^{24} \frac{\sum_{b=1}^{B}(LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy} = \frac{\sum_{h=1}^{8760} \frac{\sum_{b=1}^{B}(LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System load-weighted average	$lwLMP_{si} = \frac{\sum_{b=1}^{B}(LMP_{bi} \bullet Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh} = \frac{\sum_{b=1}^{B}(LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd} = \frac{\sum_{h=1}^{24}\sum_{b=1}^{B}(LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24}\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy} = \frac{\sum_{h=1}^{8760}\sum_{b=1}^{B}(LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760}\sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – LOAD DEFINITIONS

PJM measures load in two ways: eMTR load and accounting load. In the *2007 State of the Market Report,* both measures of load are used, as appropriate for the specific analysis. The measures of load and their applications changed after PJM's June 1, 2007, implementation of marginal losses.

eMTR Load

PJM uses eMTR load to measure peak loads and as the basis for accounting load determinations. eMTR load is supplied by PJM electricity distribution companies (EDCs) and generators and is based on the metered MWh values of tie lines and the metered values of generation MWh. For PJM Western Region and Southern Region EDCs (ComEd, AEP, DAY, DLCO, AP and Dominion), eMTR load values inherently include local, EHV (extra-high-voltage) and non-EHV losses. eMTR load values for PJM Mid-Atlantic Region EDCs inherently include local and non-EHV losses plus an allocation of metered Mid-Atlantic Region EHV losses.

eMTR load is used in state of the market reports to measure peak load. This is the total amount of generation output and net energy imports required to meet the peak load on the system, including losses.

Accounting Load

PJM uses accounting load in the settlement process. Prior to June 1, 2007, accounting load for all EDCs was equal to eMTR load. In other words, prior to June 1, 2007, accounting load included losses. Since the implementation of marginal losses on June 1, 2007, two types of accounting load have been calculated: accounting load with losses and accounting load without losses. Accounting load, without losses, for Western Region and Southern Region EDCs is calculated by subtracting non-EHV and EHV losses from eMTR load. Accounting load, without losses, for Mid-Atlantic Region EDCs is calculated by subtracting non-EHV losses and the EHV loss allocations from eMTR load. Since June 1, 2007, accounting load without losses has represented the actual retail customer load and is referred to here as accounting load.

Accounting load is used in the *2007 State of the Market Report* to measure daily, monthly and annual load. Accounting load is also used in the *2007 State of the Market Report* to weight LMP in load-weighted LMP calculations. Prior to June 1, 2007, accounting load includes losses and after June 1 accounting load excludes losses. Prior to June 1, LMP did not include losses. After June 1, LMP has included losses.

APPENDIX J – CALCULATING MARGINAL LOSSES

Since June 1, 2007, PJM's locational marginal price (LMP) has been comprised of three distinct components: system energy price, marginal losses and congestion.

Equation J-1 LMP components

$$\gamma_i = \lambda_{ref} + \gamma_i^L + \lambda_i^C,$$

where γ_i is the LMP at bus_i, λ_{ref} is the price at the reference bus, γ_i^L is the marginal loss component of the LMP at bus_i, and λ_i^C is the congestion component at bus_i.

Marginal Losses versus Average Losses

On June 1, 2007, PJM revised its methodology for determining transmission losses from average cost to nodal, marginal losses. Marginal loss pricing is based on the calculation of the incremental losses incurred as a result of a 1-MW increase in production. Marginal loss pricing permits more efficient system dispatch and decreased total production cost.

Total, Average and Marginal Losses

Power flowing across a transmission line results in losses proportional to the square of the power delivered. The materials constituting the conductors and other elements of the transmission system exhibit a characteristic impedance to the flow of power. Total transmission losses are proportional to the product of the square of the current flowing across the line, I, and the resistance of the line, R. Transmission losses are proportional to the square of the power consumed by the load, P, and the resistance of the line, R, and inversely proportional to the square of the voltage, V.[1] While this relationship differs somewhat in an alternating current (AC) as compared to a direct current (DC) system, the magnitude of losses can be approximated by the equation:

Equation J-2 Transmission losses

$$\text{Total Losses} = I^2R = \left(P^2/V^2\right)R = aP^2,$$

where $a = R/V^2$.

Since losses from a power flow of P are equal to aP^2, the average losses per MW of flow across a transmission element are:

1 Equation J-2 incorporates the substitution of the relationship I=P/V, derived from Ohm's Law, for the variable I.

Equation J-3 Average losses

Average Losses $= \left(aP^2 / P\right) = aP$.

Marginal losses are the incremental losses resulting from an increase in production and are equal to the first derivative of total losses:

Equation J-4 Marginal losses

Marginal Losses $= \dfrac{d}{dP}\left(aP^2\right) = 2aP$.

Marginal losses for an additional MW of flow are, therefore, equal to twice the average losses for the associated total flow.

Effect of Marginal Losses on LMP

To incorporate the effect of marginal losses on LMP, a penalty factor must be calculated, Pf_i, for each bus_i defined as:

Equation J-5 Penalty factor

$$Pf_i = \frac{1}{\left(1 - \dfrac{\partial P_{loss}}{\partial P_i}\right)} \cdot$$

The term $\dfrac{\partial P_{loss}}{\partial P_i}$ is called the loss factor and represents the change in system losses for a change in power P at bus_i.

If an increase in power results in an increase in losses, then the loss factor is positive:

$$0 < \frac{\partial P_{loss}}{\partial P_i} < 1 ,$$

and the resultant penalty factor at bus_i would be greater than unity:

$$Pf_i = \frac{1}{\left(1 - \dfrac{\partial P_{loss}}{\partial P_i}\right)} > 1.$$

Conversely, if an increase in power results in a decrease in losses, then the loss factor is negative:

$$-1 < \frac{\partial P_{loss}}{\partial P_i} < 0 ,$$

and the resultant penalty factor at bus_i would be less than unity:

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} < 1 .$$

The unit offer curve of a generator at each bus_i is multiplied by the respective penalty factor at bus_i. (See Equation J-5.) If the penalty factor at bus_i is greater than unity, system losses would be made greater by increasing the output of a generator at bus_i, and the unit offer curve would shift upward. Similarly, if the penalty factor at bus_i is less than unity, system losses would be reduced by increasing the output of a generator at bus_i, and the unit offer curve would shift downward. In an unconstrained system, any difference in LMP between bus_i, γ_i, and the reference bus, λ_{ref}, is the result of losses.

Loss Revenue Surplus

As demonstrated in Equation J-4, revenues resulting from marginal losses are approximately twice those collected from average losses. As demonstrated in Equation J-2, losses are proportional to the square of the power, P. As such, two loads, of equal size, served simultaneously result in losses four times greater than the losses incurred in serving either of them separately. By utilizing the penalty factor in the dispatch, losses are paid based on marginal losses rather than based on average losses. By paying for losses based on marginal instead of average losses, an overcollection occurs. Using the example of two loads, of equal size, being served simultaneously, the marginal losses associated with the combined effect of the loads is greater than the sum of the losses incurred by each load separately, thus resulting in an overcollection. These excess loss revenues are allocated to transmission users based on load plus export ratio shares:

Equation J-6 Excess loss revenue allocation

$$\text{Loss Credit} = (\text{Total Loss Surplus}) \bullet \left(\frac{\text{Customer total MWh delivered to load} + \text{exports}}{\text{Total PJM MWh delivered to load} + \text{exports}}\right).$$

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/UNIT PARTICIPATION FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system.[1] The availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[2] These factors include the impact on LMP of the cost of fuel by type, the cost of emissions allowances by type, frequently mitigated unit adders and unit markup by unit characteristics.[3]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus for every five-minute interval. In the absence of marginal losses, the UPFs associated with the set of marginal units in any given interval, for a particular load bus, always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the context of a security-constrained, least-cost dispatch solution for an interval, during which the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's offer price, multiplied by its UPF, relative to that load bus. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints, transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price is categorized as "constrained off." In addition, final LMPs calculated using UPFs may differ slightly from PJM's posted LMPs as a result of rounding and missing data. Such differentials are identified as not available (NA).

1 For another review of sensitivity factors, please refer to "PJM 101: The Basics" (June 14, 2007), p. 119 <http://www.pjm.com/services/training/downloads/pjm101part1.pdf> (6.69 MB).

2 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

3 Before the *2006 State of the Market Report,* state of the market reports had shown the impact of each marginal unit on load and on LMP based on engineering estimates whenever there were multiple marginal units.

Table K-1 shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table K-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator Contribution to LMP at X (Percentage)
A	0.5	$200.00	$100.00	85%
B	0.4	$40.00	$16.00	14%
C	0.1	$10.00	$1.00	1%
			LMP at X	
			$117.00	100%

Table K-1 shows three hypothetical, marginal generators at three different buses (A, B and C); each affects LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X, meaning that 50 percent of marginal Unit A's offer price contributes directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

Table K-1 describes the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour,

i = five-minute interval,

t = year, where t designates the current year and t-1 designates the previous year,

b = a specified load bus, where b ranges from 1 to B,

g = a specified marginal generator, where g ranges from 1 to G, and

L = interval-specific load.

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

Equation K-1 Hourly integrated load at a bus

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}$$

Load bus *LMP* is determined on a five-minute basis and is a function of marginal unit offers and UPFs in that interval:

Equation K-2 Load bus LMP

$$LMP_{bi} = \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi} \right)$$

The hourly integrated *LMP* at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

Equation K-3 Hourly integrated LMP at a bus

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$$

Total cost *(TC)* of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

Equation K-4 Hourly total system cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh} \right)$$

System load-weighted LMP for the hour *($LMPSYS_h$)* is equal to the total hourly system cost *(TC)* divided by the sum of a bus's simple 12 interval average loads in the hour:

Equation K-5 Hourly load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

The system annual, load-weighted, average *(SLW)* LMP for the year is:

Equation K-6 System annual, load-weighted, average LMP

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Markup Using UPFs

Markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve at the operating point of a specific marginal unit. UPFs can be used to calculate the impact of marginal unit markup behavior on the LMP at any individual load bus and of the LMP at any aggregation of load buses including the system LMP. The resultant markup component of LMP is a measure of market power, a market performance metric. The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the impact of marginal unit markup behavior on system LMP on an hourly integrated basis, the following steps are required.

Total cost *(TC)* of the system in the hour is equal to the product of the average LMP and the average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

Equation K-7 UPF-based system hourly total cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh}\right) = \sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right)}{12} \right]$$

System load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour:

Equation K-8 System load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(Offer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units, shown in Equation K-9, is found by substituting the marginal unit cost offers into Equation K-8:

Equation K-9 Cost-based offer system, hourly load-weighted LMP

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

The contribution of the markup by marginal units to system LMP for the hour is shown in Equation K-10 below:

Equation K-10 Impact of marginal unit markup on LMP

$$MarkUp_h = LMPSYS_h - LMPSYSCost_h$$

UPF–Weighted, Marginal Unit Markup

The price-cost markup index for a marginal unit provides a measure of market power based on the behavior of a single unit of an individual generator:

Equation K-11 Price-cost markup index

$$MarkUp_{gi} = \frac{Offer_{gi} - CostOffer_{gi}}{Offer_{gi}}$$

The UPF load-weighted, marginal unit markup (measure of unit behavior) provides a measure of market power for a given hour for the system or any aggregation of load buses. This measure of system performance equals the weighted-average markup index for all marginal units, which is a measure of unit behavior:

Equation K-12 UPF load-weighted, marginal unit markup

$$lwMarkUp_h = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs

UPFs can be used to calculate historical, cost-adjusted, load-weighted LMP for a specific time period. This method is used to disaggregate the various components of LMP, including all the separate components of unit marginal cost and unit markup, and to calculate the contributions of each component to system LMP.

The extent to which fuel cost, emission allowance cost, variable operation and maintenance cost (VOM) and markup affect the offers of marginal units depends on the share of the offer that each component represents. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_x:	$\%NO_{x\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%Mark\text{-}Up_{gi}$

The proportion of specific components of unit offers is calculated on an interval and on a unit-specific basis. Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide, emission-related cost per MWh: $SO_{2\ gt}$.

Nitrogen oxide, emission-related cost per MWh: $NO_{x\ gt}$.

Fuel costs *(FC)* are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt} = Avg FC in specified "Current Year's Period" (e.g., April 1, 2007); and

FC_{gt-1} = Avg FC in specified "Previous Year's Period" (e.g., April 1, 2006).

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs. Subtracting the proportional fuel-cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (*FCA*):

Equation K-13 Fuel-cost-adjusted offer

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}} \right) \right]$$

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers $(offer_{gi})$ in Equation K-8 (i.e., the system load-weighted LMP equation), results in the hourly fuel-cost-adjusted, load-weighted LMP:

Equation K-14 Fuel-cost-adjusted, load-weighted LMP

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAOffer_{gi} \bullet UPF_{gbi} \right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}$$

The systemwide annual, fuel-cost-adjusted, load-weighted *(SFCALW)* LMP for the year is given by the following equation:

Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP

$$Annual\_SFCALW\_LMP = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}$$

Cost-Adjusted LMP

Summing the unit's specific historical, cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (*HCAOffer*):

Equation K-16 Unit historical, cost-adjusted offer

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}}\right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}}\right)\right]$$

APPENDIX L – THREE PIVOTAL SUPPLIER TEST

PJM markets are designed to promote competitive outcomes. Market design is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitoring Unit's (MMU's) primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (i.e., a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any constraint not exempt from offer capping and for any units not exempt from offer capping. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: a) to exempt the AP South Interface from PJM's offer-capping rules; and b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted. By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in the two section 206 proceedings established by the Commission to address certain aspects of PJM's market power mitigation rules, including the application of the three pivotal supplier test, provisions for scarcity pricing,

1 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

offer caps for frequently mitigated units and competitive issues associated with certain of PJM's internal interfaces. On December 20, 2005, the presiding administrative law judge certified the "Settlement Agreement" to the Commission as uncontested. On January 27, 2006, in Docket Nos. EL03-236-006, EL04-121-000, 001 and 002, the Commission ordered that the "Settlement Agreement," including the amendments to the PJM Tariff and its OA, was in the public interest and was thereby approved and accepted for filing and made effective as set forth in the "Settlement Agreement."[2]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[3] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[4]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market and the Reliability Pricing Model (RPM) Capacity Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The three pivotal supplier test includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market.

The goal of defining the relevant market is to determine those units that are actual competitors to the units that clear in a market. The Commission definition would indicate that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition would indicate, if the marginal unit sets the clearing price based on an offer of $200 per MWh, that all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors

2 114 FERC ¶ 61,076 (2006).

3 107 FERC ¶ 61,018 (2004) (AEP Order).

4 107 FERC ¶ 61,018 (2004).

in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the three pivotal supplier test incorporates a definition of meaningful competitors that is at the high end of inclusive. It is certainly questionable whether a $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be meaningfully jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[5]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[6] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[7]

5 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

6 107 FERC ¶ 61,018 (2004).

7 107 FERC ¶ 61,018 (2004).

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the market structure makes the exercise of market power less likely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. The supply consists of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[8] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (*S*) in the market for the relief of the constraint in question. In every case, incrementally available supply is

8 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price *(P_c)* is defined as shown in Equation L-2:

Equation L-1 Incremental effective MW of supply

$MW \bullet DFAX$; and

Equation L-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c} .$$

To be relevant, the effective offer of incremental supplier *i* must be less than, or equal to, 1.5 times P_c:

Equation L-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i}{DFAX_i} \leq 1.5 \bullet P_c .$$

Where the relevant, effective incremental supply of supplier *i* is a function of price:

Equation L-4 Relevant and effective supply of supplier i

$$S_i = MW \ (P_{ie}) \bullet DFAX_i .$$

Where S_i is the relevant effective supply (relevant, incremental and effective supply) of supplier *i*, total relevant effective supply (total relevant, incremental and effective supply) for suppliers *i*=1 to n is shown in Equation L-5:

Equation L-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i .$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation L-6 shows the formula for the three pivotal supplier metric, i.e., the three pivotal residual supplier index *(RSI3)*:

Equation L-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}.$$

Where j=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out-of-merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers (j=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (j=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

APPENDIX M – GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation. ALM was replaced under the RPM Capacity Market.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Balancing energy market	Energy that is generated and financially settled during real time.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.

Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed in the Capacity Credit Market (CCM) under the Reliability Assurance Agreement (RAA).
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of one or more gas-fired turbines and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement bids (DEC)	Financial bid to purchase a defined MW level of energy up to a specified LMP, above which the bid is zero.
Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by PJM.
Disturbance control standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Economic generation	Units producing energy at an offer price less than, or equal to, LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The equivalent availability factor is the proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The equivalent maintenance outage factor is the proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The equivalent planned outage factor is the proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Frequently mitigated unit (FMU)	A unit that was offer capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Generation offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The amount by which a load-serving entity's (LSE's) unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in the "Manual 35: Definitions and Acronyms."
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.

Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Reliability*First* Corporation	Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Selective catalytic reduction (SCR)	NO_X reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Spot market	Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: $THI = T_d - (0.55 - 0.55RH) * (T_d - 58)$ where T_d is the dry-bulb temperature and *RH* is the percentage of relative humidity.

Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See "Control zone" (above).

APPENDIX N – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
AU	Associated unit
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit

CAISO	California Independent System Operator
C&I	Commercial and industrial customers
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CSP	Curtailment service provider

CT	Combustion turbine
CTR	Capacity transfer right
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor

EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GE	General Electric Company
GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator

HVDC	High-voltage direct current
Hz	Hertz
ICAP	Installed capacity
IDC	Interchange distribution calculator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LM	Load management

LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
Mon Power	Monongahela Power
MMU	PJM Market Monitoring Unit
MP	Market participant
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour

NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company

PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area

PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area

PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PMMS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan

RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TLR	Transmission loading relief

TPS	Three pivotal supplier
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation