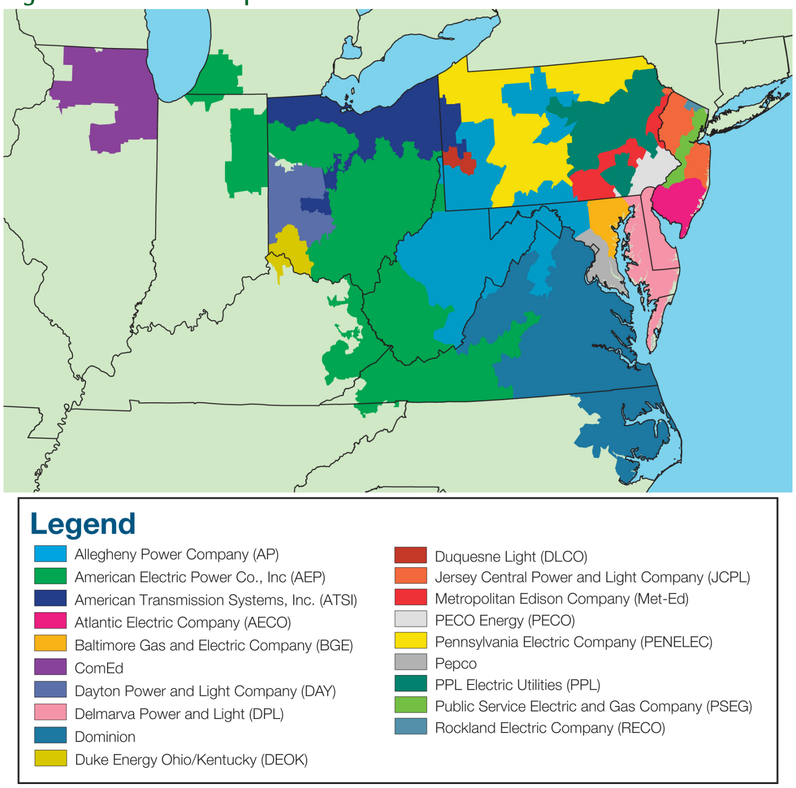
PJM Geography

During 2012, the PJM geographic footprint encompassed 19 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 19 control zones



Analysis of 2012 market results requires comparison to 2011 and certain other prior years. In 2012, PJM integrated the Duke Energy Ohio and Kentucky (DEOK) Control Zone. In 2011, PJM integrated the ATSI Control Zone. In 2006 through 2010 the PJM footprint was stable. In 2004 and 2005, 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]
- **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 through 2011).** The period from May 1, 2005, through May 31, 2011, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.
- **Phase 6 (2011).** The period from June 1, through December 31, 2011 during which PJM was comprised of the Phase 5 elements plus the ATSI Control Zone which was integrated into PJM on June 1, 2011.

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.

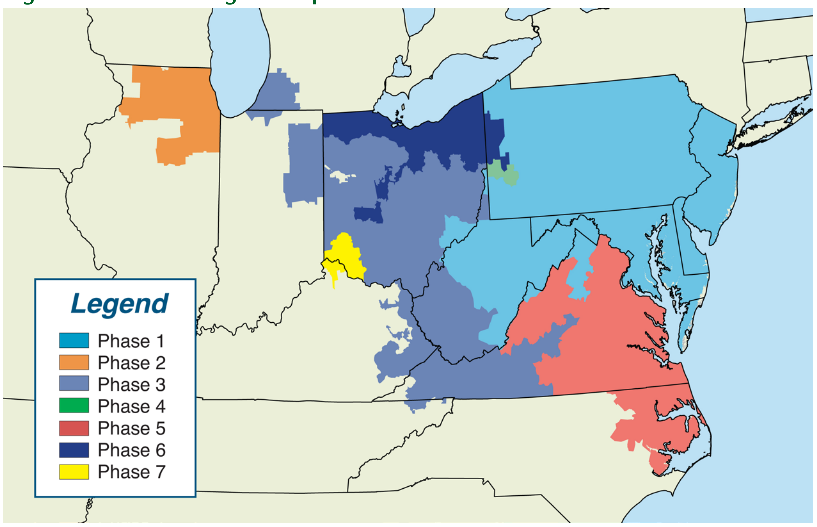
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

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.

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).

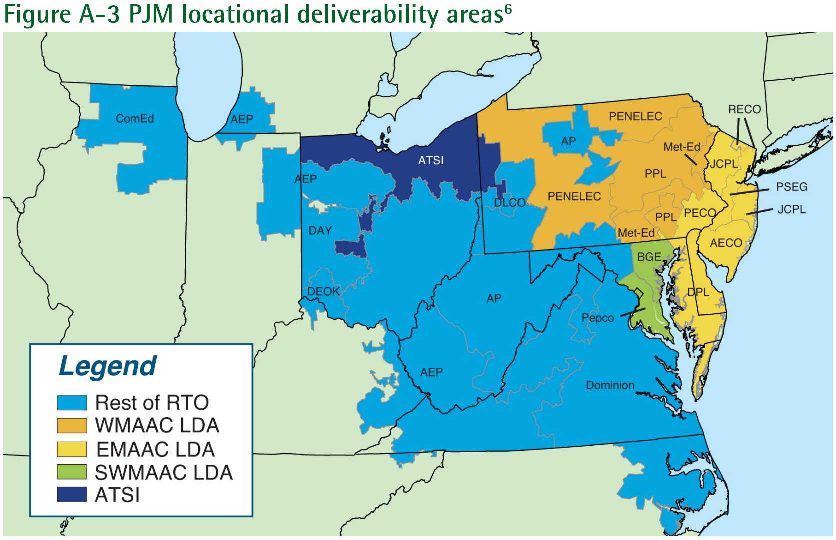
- **Phase 7 (2012).** The period from January 1, 2012, through the present, during which PJM was comprised of the Phase 6 elements plus the DEOK Control Zone which was integrated into PJM on January 1, 2012.

Figure A-2 PJM integration phases



A locational deliverability area (LDA)[5], defined as part of the RPM capacity market, is a Control Zone or part of a Control Zone within PJM with defined internal generation and defined transmission capability to import capacity in the RPM design.

Figure A-3 PJM locational deliverability areas[6]



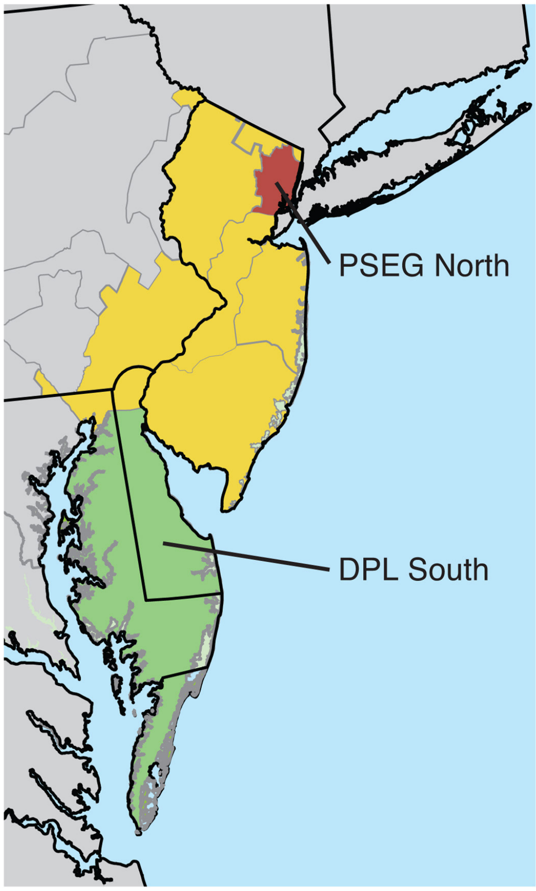
In PJM's Reliability Pricing Model (RPM) Auctions, an LDA becomes a separate market when it cannot meet its reliability requirements through a combination of economic merit order imports and internal generation without the purchase of out of merit capacity within the LDA. The regional transmission organization (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 Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, and SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) Zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4. For the 2013/2014 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, and Pepco. For the 2014/2015 Base Residual Auction, the defined markets were RTO, MAAC, and PSEG North. For the 2015/2016 Base Residual Auction, the defined markets were RTO, MAAC, and ATSI.

5 OATT Attachment DD § 2.38.

6 The ATSI Control Zone integration into PJM was effective beginning with the 2011/2012 delivery year. The ATSI Control Zone is considered a non-MAAC LDA.

Figure A-4 PJM RPM EMAAC locational deliverability area, including PSEG North and DPL South



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 Market
	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	Marginal loss component in LMPs
2008	June	Day-Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve accounting rules
	December	Three Pivotal Supplier Test in Regulation Market
2011	June	Integration of ATSI Control Zone into PJM
2012	January	Integration of DEOK Control Zone into PJM
	October	Regulation Market: Slow and fast frequency response
	October	Scarcity pricing in Energy Market

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 accounting load by hour, for 2007 to 2012.[1] The table shows the number of hours (frequency) and the 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 in 2002, the ComEd, AEP and DAY control zones in 2004, the DLCO and Dominion control zones in 2005 , the ATSI Control Zone in 2011 and the DEOK Control Zone in 2012 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2012 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 load in 2012 was 21.7 percent higher than off-peak load in 2012. Average load during on-peak hours in 2012 was 5.2 percent higher than in 2011. Off-peak load in 2012 was 5.7 percent higher than in 2011 (Table C-3).

Table C-1 Frequency distribution of PJM real-time, hourly load: 2007 to 2012

	2007		2008		2009		2010		2011		2012	
Load (GWh)	Frequency	Cumulative Percent	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%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	0	0.00%	0	0.00%	15	0.17%	12	0.14%	5	0.06%	0	0.00%
50 to 55	79	0.90%	127	1.45%	376	4.46%	272	3.24%	104	1.24%	0	0.00%
55 to 60	433	5.84%	517	7.33%	738	12.89%	582	9.89%	325	4.95%	104	1.18%
60 to 65	637	13.12%	667	14.92%	836	22.43%	699	17.87%	602	11.83%	471	6.55%
65 to 70	890	23.28%	941	25.64%	915	32.88%	805	27.05%	858	21.62%	629	13.71%
70 to 75	878	33.30%	1,048	37.57%	1,342	48.20%	1,323	42.16%	1,120	34.41%	785	22.64%
75 to 80	1,227	47.31%	1,535	55.04%	1,488	65.18%	1,272	56.68%	1,176	47.83%	1,010	34.14%
80 to 85	1,338	62.58%	1,208	68.80%	966	76.21%	948	67.50%	1,259	62.20%	1,390	49.97%
85 to 90	981	73.78%	916	79.22%	742	84.68%	794	76.56%	1,024	73.89%	1,233	64.00%
90 to 95	741	82.24%	655	86.68%	549	90.95%	659	84.09%	719	82.10%	973	75.08%
95 to 100	577	88.82%	457	91.88%	388	95.38%	487	89.65%	495	87.75%	690	82.93%
100 to 105	382	93.18%	292	95.21%	205	97.72%	318	93.28%	279	90.94%	437	87.91%
105 to 110	223	95.73%	181	97.27%	121	99.10%	195	95.50%	194	93.15%	289	91.20%
110 to 115	179	97.77%	133	98.78%	48	99.65%	151	97.23%	173	95.13%	185	93.31%
115 to 120	106	98.98%	58	99.44%	26	99.94%	108	98.46%	149	96.83%	152	95.04%
120 to 125	43	99.47%	35	99.84%	5	100.00%	84	99.42%	95	97.91%	135	96.57%
125 to 130	31	99.83%	14	100.00%	0	100.00%	40	99.87%	68	98.69%	121	97.95%
130 to 135	12	99.97%	0	100.00%	0	100.00%	11	100.00%	49	99.25%	77	98.83%
135 to 140	3	100.00%	0	100.00%	0	100.00%	0	100.00%	35	99.65%	46	99.35%
> 140	0	100.00%	0	100.00%	0	100.00%	0	100.00%	31	100.00%	57	100.00%

1 The definitions of load are discussed in the Technical Reference for PJM Markets, Section 5, "Load Definitions."

2 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-2 Off-peak and on-peak load (MW): 1998 to 2012

	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	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	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	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	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
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96
2010	72,186	88,066	1.22	70,318	85,435	1.21	12,942	13,753	1.06
2011	74,815	91,413	1.22	72,661	87,938	1.21	12,978	14,835	1.14
2012	79,047	96,194	1.22	76,930	92,199	1.20	13,182	14,426	1.09

Table C-3 Multiyear change in load: 1998 to 2012

	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%	(1.7%)	4.3%	2.8%	(1.4%)	20.9%	9.9%	(9.1%)
2000	1.8%	1.6%	(0.2%)	2.1%	2.5%	0.5%	(9.7%)	(13.3%)	(4.0%)
2001	(0.4%)	1.5%	1.9%	0.5%	1.0%	0.5%	(5.4%)	16.0%	22.6%
2002	18.4%	17.5%	(0.7%)	15.7%	16.0%	0.2%	44.6%	53.9%	6.4%
2003	5.9%	3.6%	(2.2%)	7.8%	6.4%	(1.3%)	(9.3%)	(27.3%)	(19.9%)
2004	32.8%	34.2%	1.0%	30.5%	38.7%	6.3%	95.6%	132.2%	18.7%
2005	57.5%	55.6%	(1.2%)	58.2%	45.8%	(7.8%)	17.4%	21.0%	3.0%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	(0.5%)	(10.9%)	(16.9%)	(6.8%)
2007	2.4%	3.1%	0.7%	2.1%	4.3%	2.2%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.7%)	(1.7%)	(3.5%)	(1.8%)	(1.1%)	(6.0%)	(5.0%)
2009	(4.8%)	(4.1%)	0.7%	(4.8%)	(4.2%)	0.6%	(4.0%)	(6.1%)	(2.2%)
2010	5.0%	4.4%	(0.6%)	4.7%	4.4%	(0.3%)	18.5%	30.7%	10.3%
2011	3.6%	3.8%	0.2%	3.3%	2.9%	(0.4%)	0.3%	7.9%	7.6%
2012	5.7%	5.2%	(0.4%)	5.9%	4.8%	(1.0%)	1.6%	(2.8%)	(4.3%)

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: average LMP; load-weighted average LMP; and fuel-cost-adjusted, load-weighted average LMP. Differences in average LMP measure the change in reported price. Differences in load-weighted average LMP measure the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Differences in fuel-cost-adjusted, load-weighted average LMP measure the change in reported price actually paid by load after accounting for the change in price that reflects changes in fuel prices.[3]

Any Load Serving Entity (LSE) may request to settle at a bus LMP or aggregate LMP per rules in PJM Manual 27. The zonal LMP includes every bus in the zone and is not affected by the choices of LSEs. The zonal LMP is defined by weighting each load bus LMP by its hourly individual load bus contribution to the total zonal load. The LMP for a defined aggregate is calculated by weighting each included load bus LMP by its hourly contribution to the total load of the defined aggregate.

In the Day-Ahead Energy Market buyers may submit bids at specific locations such as a transmission zone, aggregate or a single bus. Price sensitive demand bids specify price and MW quantities and a location for the bid. Market participants may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interfaces. PJM provides the definitions of the transmission zones, aggregates, and single buses.[4]

3 See the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price."

4 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 57 (December 1, 2012), Section 2, pp. 16.

Real-Time LMP

Frequency Distribution of Real-Time Average LMP

Table C-4 provides frequency distributions of PJM real-time hourly average LMP for 2007 to 2012. The table shows the number of hours (frequency) and the percent of hours (cumulative percent) when the hourly PJM real-time 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.

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): 2007 to 2012

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	56	0.64%	94	1.07%	117	1.34%	65	0.74%	66	0.75%	131	1.49%
$10 to $20	185	2.75%	129	2.54%	218	3.82%	127	2.19%	89	1.77%	510	7.30%
$20 to $30	1,571	20.68%	490	8.12%	2,970	37.73%	1,810	22.85%	1,764	21.91%	4,002	52.86%
$30 to $40	1,470	37.47%	1,443	24.54%	2,951	71.42%	3,150	58.81%	3,967	67.19%	2,801	84.74%
$40 to $50	1,108	50.11%	1,533	42.00%	1,269	85.90%	1,462	75.50%	1,334	82.42%	668	92.35%
$50 to $60	931	60.74%	1,212	55.79%	555	92.24%	766	84.25%	489	88.00%	244	95.13%
$60 to $70	827	70.18%	845	65.41%	276	95.39%	427	89.12%	303	91.46%	136	96.68%
$70 to $80	726	78.47%	709	73.49%	151	97.11%	274	92.25%	174	93.45%	75	97.53%
$80 to $90	646	85.84%	502	79.20%	95	98.20%	165	94.13%	133	94.97%	51	98.11%
$90 to $100	451	90.99%	385	83.58%	62	98.90%	134	95.66%	108	96.20%	38	98.54%
$100 to $110	240	93.73%	352	87.59%	30	99.25%	82	96.60%	61	96.89%	32	98.91%
$110 to $120	178	95.76%	265	90.61%	21	99.49%	71	97.41%	61	97.59%	20	99.13%
$120 to $130	110	97.02%	199	92.87%	15	99.66%	61	98.11%	46	98.12%	15	99.31%
$130 to $140	76	97.89%	144	94.51%	7	99.74%	44	98.61%	33	98.49%	10	99.42%
$140 to $150	53	98.49%	111	95.78%	9	99.84%	29	98.94%	25	98.78%	7	99.50%
$150 to $160	26	98.79%	102	96.94%	3	99.87%	22	99.19%	25	99.06%	8	99.59%
$160 to $170	29	99.12%	68	97.71%	3	99.91%	11	99.32%	17	99.26%	5	99.65%
$170 to $180	18	99.33%	52	98.30%	5	99.97%	13	99.46%	15	99.43%	1	99.66%
$180 to $190	9	99.43%	45	98.82%	0	99.97%	12	99.60%	6	99.50%	2	99.68%
$190 to $200	15	99.60%	29	99.15%	1	99.98%	9	99.70%	8	99.59%	3	99.72%
$200 to $210	6	99.67%	20	99.37%	1	99.99%	7	99.78%	6	99.66%	2	99.74%
$210 to $220	4	99.71%	11	99.50%	1	100.00%	4	99.83%	5	99.71%	1	99.75%
$220 to $230	4	99.76%	14	99.66%	0	100.00%	3	99.86%	4	99.76%	0	99.75%
$230 to $240	2	99.78%	10	99.77%	0	100.00%	5	99.92%	0	99.76%	4	99.80%
$240 to $250	5	99.84%	2	99.80%	0	100.00%	3	99.95%	3	99.79%	5	99.85%
$250 to $260	2	99.86%	5	99.85%	0	100.00%	1	99.97%	3	99.83%	5	99.91%
$260 to $270	4	99.91%	4	99.90%	0	100.00%	0	99.97%	3	99.86%	0	99.91%
$270 to $280	0	99.91%	1	99.91%	0	100.00%	0	99.97%	3	99.90%	1	99.92%
$280 to $290	0	99.91%	1	99.92%	0	100.00%	1	99.98%	0	99.90%	1	99.93%
$290 to $300	0	99.91%	0	99.92%	0	100.00%	0	99.98%	2	99.92%	0	99.93%
$300 to $400	2	99.93%	6	99.99%	0	100.00%	2	100.00%	4	99.97%	6	100.00%
$400 to $500	4	99.98%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$500 to $600	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
$600 to $700	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%
> $700	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted Average LMP

Table C-5 shows load-weighted, average real-time LMP for 2011 and 2012 during off-peak and on-peak periods.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): 2011 to 2012

	2011			2012			Difference 2011 to 2012		
	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	$37.28	$54.07	1.45	$28.49	$41.61	1.46	(23.6%)	(23.0%)	0.7%
Median	$32.37	$41.26	1.27	$26.89	$33.67	1.25	(16.9%)	(18.4%)	(1.7%)
Standard deviation	$20.01	$40.74	2.04	$13.56	$28.85	2.13	(32.3%)	(29.2%)	4.5%

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. Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up between 80 percent and 90 percent of marginal cost on average, 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 marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[5] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2011 and 2012, the load-weighted LMP for 2012 was adjusted to reflect the daily price of fuels and emission allowances used by marginal units from a base period, 2011. The fuel cost adjusted, load-weighted LMP for 2012 is compared to the load-weighted LMP for 2011.[6]

Table C-6 shows the real-time, load-weighted, average LMP for 2011 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2012 for on-peak and off-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2012 on-peak hours was 12.2 percent lower than the load-weighted, average LMP for 2011 on-peak hours. The fuel-cost adjusted load-weighted, average LMP for 2012 off-peak hours was 7.5 percent lower than the load-weighted, average LMP for 2011 off-peak hours. The mix of fuel types and costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): 2012

	2011 Load-Weighted LMP	2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Off Peak	$37.28	$34.50	(7.5%)
On Peak	$54.07	$47.50	(12.2%)

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

Table C-7 shows the PJM load-weighted, average LMP during constrained hours for 2011 and 2012.[7]

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): 2011 to 2012

	2011	2012	Difference
Average	$47.36	$36.52	(22.9%)
Median	$37.05	$31.03	(16.3%)
Standard deviation	$34.90	$24.67	(29.3%)

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2011 and 2012.

5 See the *2012 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market," at Table 2-17, "Type of fuel used (By marginal units): Calendar year 2012."

6 See the *Technical Reference for PJM Markets*, Section 7, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

Table C-8 PJM real-time load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): 2011 to 2012

	2011			2012		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$35.14	$47.36	34.8%	$26.36	$36.52	38.5%
Median	$33.21	$37.05	11.6%	$27.43	$31.03	13.1%
Standard deviation	$15.69	$34.90	122.4%	$11.56	$24.67	113.3%

Table C-9 shows the number of hours and the number of constrained hours in each month in 2011 and 2012.

Table C-9 PJM real-time constrained hours: 2011 to 2012

	2011 Constrained Hours	2012 Constrained Hours	Total Hours
Jan	678	537	744
Feb	518	633	672
Mar	578	661	743
Apr	655	669	720
May	590	632	744
Jun	622	505	720
Jul	630	676	744
Aug	658	630	744
Sep	687	649	720
Oct	717	724	744
Nov	641	663	721
Dec	669	625	744
Avg	637	634	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2012 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2012 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2007 to 2012. Together the tables show the frequency distribution by hours for the two markets. In the Real-Time Energy Market, prices reached a high for the year of $398.80 per MWh on May 29, 2012, in the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices reached a high for the year of $273.45 per MWh on June 21, 2012, in the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): 2007 to 2012

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	3	0.03%	0	0.00%	23	0.26%	5	0.06%	0	0.00%	19	0.22%
$10 to $20	88	1.04%	19	0.22%	343	4.18%	31	0.41%	33	0.38%	467	5.53%
$20 to $30	1,291	15.78%	320	3.86%	2,380	31.35%	1,502	17.56%	1,595	18.58%	3,402	44.26%
$30 to $40	1,495	32.84%	1,148	16.93%	3,221	68.12%	2,851	50.10%	3,359	56.93%	3,521	84.35%
$40 to $50	1,221	46.78%	1,546	34.53%	1,717	87.72%	2,131	74.43%	2,024	80.03%	908	94.68%
$50 to $60	1,266	61.23%	1,491	51.50%	557	94.08%	954	85.32%	872	89.99%	247	97.50%
$60 to $70	1,301	76.08%	1,107	64.11%	253	96.96%	471	90.70%	406	94.62%	106	98.70%
$70 to $80	939	86.80%	942	74.83%	138	98.54%	302	94.14%	174	96.61%	39	99.15%
$80 to $90	504	92.56%	682	82.59%	68	99.32%	193	96.35%	87	97.60%	21	99.39%
$90 to $100	264	95.57%	542	88.76%	33	99.69%	125	97.77%	61	98.30%	12	99.52%
$100 to $110	155	97.34%	289	92.05%	19	99.91%	86	98.76%	29	98.63%	7	99.60%
$110 to $120	104	98.53%	193	94.25%	6	99.98%	46	99.28%	30	98.97%	6	99.67%
$120 to $130	59	99.20%	131	95.74%	2	100.00%	29	99.61%	16	99.16%	7	99.75%
$130 to $140	33	99.58%	112	97.02%	0	100.00%	14	99.77%	21	99.39%	4	99.80%
$140 to $150	13	99.73%	67	97.78%	0	100.00%	7	99.85%	17	99.59%	2	99.82%
$150 to $160	8	99.82%	54	98.39%	0	100.00%	6	99.92%	7	99.67%	1	99.83%
$160 to $170	7	99.90%	46	98.92%	0	100.00%	3	99.95%	3	99.70%	3	99.86%
$170 to $180	3	99.93%	23	99.18%	0	100.00%	2	99.98%	2	99.73%	1	99.87%
$180 to $190	4	99.98%	20	99.41%	0	100.00%	0	99.98%	2	99.75%	0	99.87%
$190 to $200	1	99.99%	16	99.59%	0	100.00%	2	100.00%	2	99.77%	2	99.90%
$200 to $210	1	100.00%	8	99.68%	0	100.00%	0	100.00%	1	99.78%	2	99.92%
$210 to $220	0	100.00%	9	99.78%	0	100.00%	0	100.00%	0	99.78%	2	99.94%
$220 to $230	0	100.00%	4	99.83%	0	100.00%	0	100.00%	2	99.81%	1	99.95%
$230 to $240	0	100.00%	3	99.86%	0	100.00%	0	100.00%	1	99.82%	2	99.98%
$240 to $250	0	100.00%	2	99.89%	0	100.00%	0	100.00%	0	99.82%	0	99.98%
$250 to $260	0	100.00%	0	99.89%	0	100.00%	0	100.00%	2	99.84%	1	99.99%
$260 to $270	0	100.00%	4	99.93%	0	100.00%	0	100.00%	2	99.86%	0	99.99%
$270 to $280	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.86%	1	100.00%
$280 to $290	0	100.00%	2	99.95%	0	100.00%	0	100.00%	0	99.86%	0	100.00%
$290 to $300	0	100.00%	2	99.98%	0	100.00%	0	100.00%	4	99.91%	0	100.00%
>$300	0	100.00%	2	100.00%	0	100.00%	0	100.00%	8	100.00%	0	100.00%

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

Table C-11 shows PJM average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets in calendar year 2012. Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP in 2012 during the on-peak and off-peak hours.

Table C-11 Off-peak and on-peak, average day-ahead and real-time LMP (Dollars per MWh): 2012

	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	$27.88	$38.46	1.38	$27.29	$39.83	1.46	(2.1%)	3.6%	5.8%
Median	$27.15	$34.71	1.28	$26.18	$33.13	1.27	(3.6%)	(4.5%)	(1.0%)
Standard deviation	$7.66	$15.86	2.07	$12.74	$25.47	2.00	66.4%	60.6%	(3.5%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): 2012

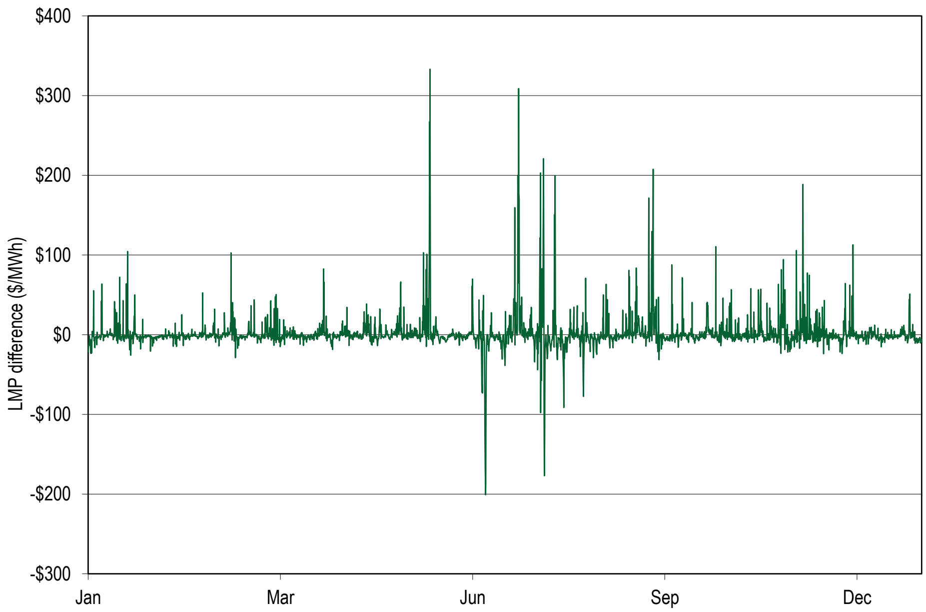
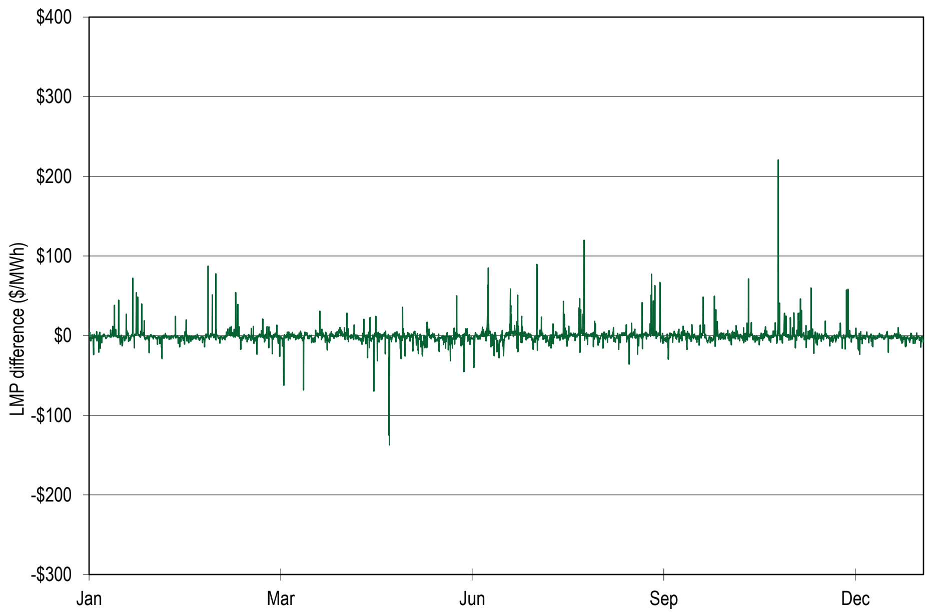


Figure C-2 Hourly real-time average LMP minus day-ahead average LMP (Off-peak hours): 2012



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

Table C-12 and Table C-13 show the on-peak and off-peak, average LMP for each zone in the Day-Ahead and Real-Time Energy Markets in 2011 and 2012.[8]

Table C-12 On-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent Real Time	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$57.01	$57.22	$0.21	0.37%	$40.68	$40.98	$0.30	0.73%
AEP	$45.90	$45.70	($0.20)	(0.45%)	$36.32	$37.59	$1.27	3.38%
AP	$50.60	$50.85	$0.24	0.48%	$38.20	$39.51	$1.31	3.32%
ATSI	$46.98	$46.85	($0.14)	(0.29%)	$37.19	$38.93	$1.74	4.48%
BGE	$58.02	$59.24	$1.22	2.06%	$43.66	$45.16	$1.50	3.32%
ComEd	$41.48	$41.42	($0.06)	(0.14%)	$34.22	$36.13	$1.92	5.31%
DAY	$45.93	$46.16	$0.23	0.50%	$37.14	$38.43	$1.29	3.35%
DEOK	NA	NA	NA	NA	$35.47	$36.60	$1.13	3.09%
DLCO	$46.09	$46.50	$0.41	0.88%	$36.81	$37.97	$1.16	3.06%
Dominion	$53.87	$54.63	$0.76	1.39%	$40.17	$41.65	$1.47	3.54%
DPL	$56.88	$56.84	($0.04)	(0.06%)	$42.80	$43.49	$0.69	1.59%
JCPL	$56.40	$57.51	$1.12	1.94%	$40.47	$41.00	$0.54	1.31%
Met-Ed	$54.32	$55.19	$0.87	1.58%	$39.95	$41.31	$1.36	3.30%
PECO	$56.30	$55.88	($0.42)	(0.75%)	$40.34	$41.14	$0.80	1.95%
PENELEC	$50.44	$51.17	$0.73	1.43%	$39.14	$40.27	$1.13	2.81%
Pepco	$56.45	$56.47	$0.02	0.03%	$42.60	$44.19	$1.59	3.60%
PPL	$54.17	$55.48	$1.31	2.37%	$39.14	$40.24	$1.09	2.72%
PSEG	$57.41	$58.27	$0.87	1.49%	$41.04	$41.91	$0.86	2.06%
RECO	$54.22	$52.93	($1.30)	(2.45%)	$40.07	$41.35	$1.28	3.09%

Table C-13 Off-peak, zonal, average day-ahead and real-time LMP (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day Ahead	Real Time	Difference	Difference as Percent Real Time	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$39.88	$39.13	($0.76)	(1.93%)	$28.88	$28.32	($0.56)	(1.98%)
AEP	$33.58	$33.23	($0.35)	(1.06%)	$27.23	$26.60	($0.64)	(2.39%)
AP	$36.30	$35.99	($0.32)	(0.89%)	$28.16	$27.51	($0.65)	(2.36%)
ATSI	$32.71	$32.65	($0.06)	(0.19%)	$27.70	$27.12	($0.58)	(2.15%)
BGE	$40.51	$40.27	($0.23)	(0.58%)	$31.05	$30.34	($0.72)	(2.36%)
ComEd	$26.46	$26.22	($0.24)	(0.91%)	$24.10	$23.29	($0.81)	(3.50%)
DAY	$33.51	$33.17	($0.34)	(1.02%)	$27.73	$27.07	($0.66)	(2.43%)
DEOK	NA	NA	NA	NA	$26.63	$25.98	($0.65)	(2.51%)
DLCO	$32.61	$32.43	($0.19)	(0.57%)	$26.96	$26.30	($0.66)	(2.52%)
Dominion	$39.14	$39.19	$0.05	0.13%	$29.37	$28.66	($0.71)	(2.46%)
DPL	$40.12	$39.04	($1.08)	(2.77%)	$29.83	$29.78	($0.05)	(0.16%)
JCPL	$39.91	$39.05	($0.85)	(2.19%)	$28.84	$28.04	($0.80)	(2.86%)
Met-Ed	$38.40	$37.66	($0.75)	(1.98%)	$28.24	$27.59	($0.65)	(2.35%)
PECO	$39.29	$38.44	($0.86)	(2.23%)	$28.53	$27.96	($0.57)	(2.05%)
PENELEC	$36.12	$35.79	($0.33)	(0.92%)	$28.45	$27.62	($0.83)	(3.00%)
Pepco	$39.85	$39.38	($0.48)	(1.21%)	$30.37	$29.50	($0.86)	(2.93%)
PPL	$38.28	$37.43	($0.85)	(2.26%)	$28.02	$27.47	($0.56)	(2.04%)
PSEG	$40.39	$39.36	($1.03)	(2.62%)	$29.30	$28.61	($0.69)	(2.41%)
RECO	$38.46	$36.74	($1.72)	(4.68%)	$28.88	$28.30	($0.58)	(2.06%)

8 Tables C-12 and C-13 in the *2011 State of the Market Report for PJM* incorrectly reported the LMP for the zones. The tables now show the correct LMP for each zone in 2011.

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

Table C-14 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 2012.

Table C-14 PJM day-ahead and real-time, market-constrained hours: 2012

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	537	744
Feb	696	633	696
Mar	743	661	743
Apr	720	669	720
May	744	632	744
Jun	720	505	720
Jul	744	676	744
Aug	744	630	744
Sep	720	649	720
Oct	744	724	744
Nov	721	663	721
Dec	744	625	744
Avg	732	634	732

Table C-15 shows PJM average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets.

Table C-15 PJM average LMP during constrained and unconstrained hours (Dollars per MWh): 2012

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$0.00	$32.79	NA	$25.15	$34.35	36.6%
Median	$0.00	$30.89	NA	$26.45	$30.13	13.9%
Standard deviation	$0.00	$13.27	NA	$12.08	$21.44	77.5%

LMP by Zone and by Jurisdiction

Zonal Real-Time, Average LMP

Table C-16 Zonal real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$47.56	$34.20	($13.35)	(28.1%)
AEP	$39.04	$31.70	($7.33)	(18.8%)
AP	$42.91	$33.08	($9.82)	(22.9%)
ATSI	$39.24	$32.61	($6.63)	(16.9%)
BGE	$49.11	$37.22	($11.88)	(24.2%)
ComEd	$33.30	$29.25	($4.05)	(12.2%)
DAY	$39.22	$32.35	($6.87)	(17.5%)
DEOK	NA	$30.91	NA	NA
DLCO	$38.98	$31.72	($7.26)	(18.6%)
Dominion	$46.38	$34.69	($11.69)	(25.2%)
DPL	$47.33	$36.15	($11.18)	(23.6%)
JCPL	$47.65	$34.06	($13.59)	(28.5%)
Met-Ed	$45.82	$33.96	($11.86)	(25.9%)
PECO	$46.56	$34.08	($12.48)	(26.8%)
PENELEC	$42.95	$33.50	($9.46)	(22.0%)
Pepco	$47.34	$36.33	($11.01)	(23.3%)
PPL	$45.84	$33.40	($12.44)	(27.1%)
PSEG	$48.17	$34.79	($13.38)	(27.8%)
RECO	$44.28	$34.36	($9.92)	(22.4%)
PJM	$42.84	$33.11	($9.73)	(22.7%)

Real-Time, Average LMP by Jurisdiction

Table C-17 Jurisdiction real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$46.61	$34.50	($12.11)	(26.0%)
Illinois	$33.30	$29.25	($4.05)	(12.2%)
Indiana	$38.45	$31.56	($6.89)	(17.9%)
Kentucky	$38.39	$31.40	($6.99)	(18.2%)
Maryland	$48.06	$36.64	($11.42)	(23.8%)
Michigan	$39.30	$32.00	($7.30)	(18.6%)
New Jersey	$47.88	$34.50	($13.38)	(28.0%)
North Carolina	$45.23	$34.26	($10.97)	(24.3%)
Ohio	$39.38	$32.02	($7.36)	(18.7%)
Pennsylvania	$44.48	$33.39	($11.09)	(24.9%)
Tennessee	$38.35	$31.20	($7.16)	(18.7%)
Virginia	$45.36	$34.39	($10.97)	(24.2%)
West Virginia	$39.72	$31.62	($8.09)	(20.4%)
District of Columbia	$47.41	$36.92	($10.49)	(22.1%)

Hub Real-Time, Average LMP

Table C-18 Hub real-time, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AEP Gen Hub	$37.08	$30.46	($6.62)	(17.9%)
AEP-DAY Hub	$38.55	$31.55	($7.00)	(18.2%)
ATSI Gen Hub	$38.87	$32.19	($6.68)	(17.2%)
Chicago Gen Hub	$32.25	$28.28	($3.97)	(12.3%)
Chicago Hub	$33.48	$29.43	($4.05)	(12.1%)
Dominion Hub	$45.84	$34.19	($11.65)	(25.4%)
Eastern Hub	$47.71	$36.55	($11.16)	(23.4%)
N Illinois Hub	$33.07	$28.95	($4.12)	(12.5%)
New Jersey Hub	$47.88	$34.45	($13.43)	(28.1%)
Ohio Hub	$38.58	$31.66	($6.93)	(18.0%)
West Interface Hub	$40.57	$32.50	($8.07)	(19.9%)
Western Hub	$43.56	$33.90	($9.66)	(22.2%)

Zonal Real-Time, Load-Weighted, Average LMP

Table C-19 Zonal real-time, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$53.11	$37.55	($15.57)	(29.3%)
AEP	$40.92	$33.15	($7.77)	(19.0%)
AP	$45.49	$34.86	($10.63)	(23.4%)
ATSI	$42.09	$34.42	($7.67)	(18.2%)
BGE	$54.27	$40.02	($14.25)	(26.3%)
ComEd	$36.20	$31.76	($4.44)	(12.3%)
DAY	$41.78	$34.25	($7.54)	(18.0%)
DEOK	NA	$32.67	NA	NA
DLCO	$41.31	$33.53	($7.78)	(18.8%)
Dominion	$50.59	$37.28	($13.31)	(26.3%)
DPL	$52.20	$39.53	($12.67)	(24.3%)
JCPL	$53.48	$37.34	($16.14)	(30.2%)
Met-Ed	$49.51	$36.30	($13.21)	(26.7%)
PECO	$50.83	$36.78	($14.05)	(27.6%)
PENELEC	$45.12	$35.10	($10.02)	(22.2%)
Pepco	$51.84	$39.08	($12.77)	(24.6%)
PPL	$49.31	$35.44	($13.87)	(28.1%)
PSEG	$52.68	$37.48	($15.20)	(28.9%)
RECO	$49.66	$37.80	($11.86)	(23.9%)
PJM	$45.94	$35.23	($10.71)	(23.3%)

Real-Time, Load-Weighted, Average LMP by Jurisdiction

Table C-20 Jurisdiction real-time, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$51.13	$37.47	($13.66)	(26.7%)
Illinois	$36.20	$31.76	($4.44)	(12.3%)
Indiana	$40.12	$32.96	($7.15)	(17.8%)
Kentucky	$40.41	$32.75	($7.67)	(19.0%)
Maryland	$52.98	$39.53	($13.46)	(25.4%)
Michigan	$41.60	$34.08	($7.52)	(18.1%)
New Jersey	$52.91	$37.45	($15.46)	(29.2%)
North Carolina	$49.20	$36.54	($12.66)	(25.7%)
Ohio	$41.54	$33.70	($7.85)	(18.9%)
Pennsylvania	$47.65	$35.46	($12.19)	(25.6%)
Tennessee	$40.27	$32.58	($7.69)	(19.1%)
Virginia	$49.22	$36.82	($12.39)	(25.2%)
West Virginia	$41.56	$32.98	($8.58)	(20.6%)
District of Columbia	$50.88	$39.33	($11.56)	(22.7%)

Zonal Day-Ahead, Average LMP

Table C-21 Zonal day-ahead, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$47.86	$34.36	($13.50)	(28.2%)
AEP	$39.32	$31.45	($7.87)	(20.0%)
AP	$42.96	$32.82	($10.14)	(23.6%)
ATSI	$39.34	$32.11	($7.23)	(18.4%)
BGE	$48.66	$36.91	($11.75)	(24.2%)
ComEd	$33.46	$28.80	($4.66)	(13.9%)
DAY	$39.29	$32.10	($7.19)	(18.3%)
DEOK	NA	$30.73	NA	NA
DLCO	$38.89	$31.53	($7.36)	(18.9%)
Dominion	$46.00	$34.39	($11.62)	(25.2%)
DPL	$47.93	$35.86	($12.07)	(25.2%)
JCPL	$47.59	$34.24	($13.35)	(28.0%)
Met-Ed	$45.82	$33.68	($12.14)	(26.5%)
PECO	$47.21	$34.02	($13.20)	(28.0%)
PENELEC	$42.79	$33.41	($9.37)	(21.9%)
Pepco	$47.58	$36.05	($11.53)	(24.2%)
PPL	$45.68	$33.19	($12.49)	(27.3%)
PSEG	$48.32	$34.76	($13.56)	(28.1%)
RECO	$45.80	$34.08	($11.72)	(25.6%)
PJM	$42.52	$32.79	($9.73)	(22.9%)

Day-Ahead, Average LMP by Jurisdiction

Table C-22 Jurisdiction day-ahead, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$47.10	$34.42	($12.68)	(26.9%)
Illinois	$33.46	$28.80	($4.66)	(13.9%)
Indiana	$38.51	$30.96	($7.56)	(19.6%)
Kentucky	$38.50	$31.22	($7.28)	(18.9%)
Maryland	$48.17	$36.57	($11.60)	(24.1%)
Michigan	$39.48	$31.30	($8.18)	(20.7%)
New Jersey	$48.01	$34.54	($13.47)	(28.1%)
North Carolina	$44.86	$33.89	($10.97)	(24.4%)
Ohio	$39.36	$31.50	($7.85)	(20.0%)
Pennsylvania	$44.64	$33.25	($11.39)	(25.5%)
Tennessee	$38.61	$30.71	($7.90)	(20.5%)
Virginia	$45.23	$34.08	($11.15)	(24.7%)
West Virginia	$40.27	$31.49	($8.78)	(21.8%)
District of Columbia	$47.59	$36.43	($11.16)	(23.5%)

Zonal Day-Ahead, Load-Weighted Average LMP

Table C-23 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
AECO	$53.09	$37.36	($15.74)	(29.6%)
AEP	$41.12	$32.71	($8.41)	(20.5%)
AP	$45.10	$34.29	($10.81)	(24.0%)
ATSI	$41.89	$33.55	($8.34)	(19.9%)
BGE	$53.21	$39.55	($13.66)	(25.7%)
ComEd	$35.72	$30.72	($4.99)	(14.0%)
DAY	$41.54	$33.76	($7.78)	(18.7%)
DEOK	NA	$32.18	NA	NA
DLCO	$40.98	$33.05	($7.93)	(19.4%)
Dominion	$49.78	$36.56	($13.22)	(26.6%)
DPL	$52.62	$38.91	($13.71)	(26.1%)
JCPL	$52.22	$37.03	($15.19)	(29.1%)
Met-Ed	$48.62	$35.44	($13.18)	(27.1%)
PECO	$51.11	$36.40	($14.70)	(28.8%)
PENELEC	$44.35	$34.69	($9.66)	(21.8%)
Pepco	$51.03	$38.26	($12.77)	(25.0%)
PPL	$48.69	$34.82	($13.87)	(28.5%)
PSEG	$52.23	$37.25	($14.98)	(28.7%)
RECO	$49.96	$36.91	($13.05)	(26.1%)
PJM	$45.19	$34.55	($10.64)	(23.5%)

Day-Ahead, Load-Weighted, Average LMP by Jurisdiction

Table C-24 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): 2011 and 2012

	2011	2012	Difference	Difference as Percent of 2011
Delaware	$51.46	$37.17	($14.29)	(27.8%)
Illinois	$35.72	$30.72	($4.99)	(14.0%)
Indiana	$40.15	$32.21	($7.95)	(19.8%)
Kentucky	$40.41	$32.41	($8.00)	(19.8%)
Maryland	$52.23	$39.02	($13.22)	(25.3%)
Michigan	$41.37	$32.87	($8.49)	(20.5%)
New Jersey	$52.29	$37.19	($15.10)	(28.9%)
North Carolina	$48.74	$36.03	($12.71)	(26.1%)
Ohio	$41.65	$32.90	($8.75)	(21.0%)
Pennsylvania	$47.27	$34.93	($12.33)	(26.1%)
Tennessee	$40.58	$31.75	($8.83)	(21.8%)
Virginia	$48.65	$36.07	($12.58)	(25.9%)
West Virginia	$42.07	$32.75	($9.32)	(22.2%)
District of Columbia	$50.57	$38.58	($11.99)	(23.7%)

Zonal Price Differences

Table C-25 Zonal day-ahead and real-time average LMP (Dollars per MWh): 2012

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
AECO	$34.36	$34.20	($0.16)	(0.5%)
AEP	$31.45	$31.70	$0.25	0.8%
AP	$32.82	$33.08	$0.26	0.8%
ATSI	$32.11	$32.61	$0.50	1.5%
BGE	$36.91	$37.22	$0.31	0.8%
ComEd	$28.80	$29.25	$0.45	1.6%
DAY	$32.10	$32.35	$0.25	0.8%
DEOK	$30.73	$30.91	$0.18	0.6%
DLCO	$31.53	$31.72	$0.18	0.6%
Dominion	$34.39	$34.69	$0.31	0.9%
DPL	$35.86	$36.15	$0.29	0.8%
JCPL	$34.24	$34.06	($0.18)	(0.5%)
Met-Ed	$33.68	$33.96	$0.29	0.8%
PECO	$34.02	$34.08	$0.07	0.2%
PENELEC	$33.41	$33.50	$0.08	0.2%
Pepco	$36.05	$36.33	$0.28	0.8%
PPL	$33.19	$33.40	$0.21	0.6%
PSEG	$34.76	$34.79	$0.03	0.1%
RECO	$34.08	$34.36	$0.28	0.8%
PJM	$32.79	$33.11	$0.32	1.0%

Jurisdictional Price Differences

Table C-26 Jurisdiction day-ahead and real-time average LMP (Dollars per MWh): 2012

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$34.42	$34.50	$0.07	0.2%
Illinois	$28.80	$29.25	$0.45	1.6%
Indiana	$30.96	$31.56	$0.60	2.0%
Kentucky	$31.22	$31.40	$0.18	0.6%
Maryland	$36.57	$36.64	$0.07	0.2%
Michigan	$31.30	$32.00	$0.71	2.3%
New Jersey	$34.54	$34.50	($0.05)	(0.1%)
North Carolina	$33.89	$34.26	$0.37	1.1%
Ohio	$31.50	$32.02	$0.52	1.6%
Pennsylvania	$33.25	$33.39	$0.14	0.4%
Tennessee	$30.71	$31.20	$0.49	1.6%
Virginia	$34.08	$34.39	$0.31	0.9%
West Virginia	$31.49	$31.62	$0.13	0.4%
District of Columbia	$36.43	$36.92	$0.49	1.3%

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.[9] 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.

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.[10] 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.

Levels of offer capping have generally been low and stable over the last five years. Table C-27 through Table C-30 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.

9 See OA Schedule 1, § 6.4.2

10 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test."

Table C-27 Average day-ahead, offer-capped units: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.0%	0.7	0.1%	0.6	0.1%	0.1	0.0%	0.0	0.0%
Feb	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.0	0.0%	0.8	0.1%
Mar	0.0	0.0%	0.6	0.1%	0.3	0.0%	0.1	0.0%	0.2	0.0%
Apr	0.2	0.0%	0.0	0.0%	0.8	0.1%	0.3	0.0%	0.0	0.0%
May	0.6	0.1%	0.1	0.0%	1.2	0.1%	0.1	0.0%	0.8	0.1%
Jun	1.5	0.1%	0.3	0.0%	2.0	0.2%	0.0	0.0%	0.1	0.0%
Jul	1.7	0.2%	0.0	0.0%	2.8	0.3%	0.2	0.0%	0.2	0.0%
Aug	0.2	0.0%	0.4	0.0%	0.5	0.0%	0.3	0.0%	0.2	0.0%
Sep	0.4	0.0%	0.2	0.0%	0.5	0.0%	0.3	0.0%	3.0	0.2%
Oct	0.4	0.0%	0.1	0.0%	0.3	0.0%	0.0	0.0%	5.9	0.5%
Nov	0.5	0.0%	0.0	0.0%	0.3	0.0%	0.2	0.0%	5.4	0.4%
Dec	1.3	0.1%	0.3	0.0%	0.0	0.0%	0.0	0.0%	9.6	0.8%

Table C-28 Average day-ahead, offer-capped MW: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	16	0.0%	98	0.1%	50	0.1%	9	0.0%	0	0.0%
Feb	11	0.0%	30	0.0%	29	0.0%	0	0.0%	515	0.5%
Mar	2	0.0%	47	0.1%	17	0.0%	13	0.0%	77	0.1%
Apr	31	0.0%	0	0.0%	98	0.1%	33	0.0%	1	0.0%
May	15	0.0%	9	0.0%	117	0.1%	14	0.0%	62	0.1%
Jun	91	0.1%	42	0.0%	129	0.1%	4	0.0%	4	0.0%
Jul	110	0.1%	0	0.0%	143	0.1%	20	0.0%	15	0.0%
Aug	35	0.0%	35	0.0%	61	0.1%	45	0.0%	30	0.0%
Sep	66	0.1%	10	0.0%	34	0.0%	38	0.0%	548	0.6%
Oct	39	0.0%	3	0.0%	26	0.0%	1	0.0%	847	1.0%
Nov	47	0.1%	0	0.0%	23	0.0%	23	0.0%	943	1.1%
Dec	187	0.2%	29	0.0%	0	0.0%	0	0.0%	1568	1.7%

Table C-29 Average real-time, offer-capped units: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	3.1	0.3%	2.4	0.2%	2.3	0.2%	2.8	0.3%	3.0	0.3%
Feb	2.6	0.3%	1.1	0.1%	1.9	0.2%	2.3	0.2%	6.5	0.5%
Mar	2.7	0.3%	1.8	0.2%	2.5	0.2%	1.6	0.1%	5.7	0.5%
Apr	3.1	0.3%	1.8	0.2%	3.2	0.3%	2.8	0.3%	4.0	0.3%
May	2.1	0.2%	1.0	0.1%	4.5	0.4%	2.8	0.3%	4.5	0.4%
Jun	8.7	0.8%	1.3	0.1%	7.1	0.7%	4.3	0.4%	3.3	0.3%
Jul	5.7	0.6%	1.1	0.1%	9.3	0.9%	8.0	0.7%	5.6	0.5%
Aug	2.0	0.2%	3.0	0.3%	5.8	0.5%	3.2	0.3%	3.4	0.3%
Sep	4.8	0.5%	1.6	0.1%	6.2	0.6%	6.4	0.6%	5.2	0.4%
Oct	2.5	0.2%	1.2	0.1%	3.5	0.3%	4.3	0.4%	6.2	0.5%
Nov	2.2	0.2%	0.6	0.1%	3.1	0.3%	4.1	0.4%	6.3	0.5%
Dec	2.5	0.2%	1.3	0.1%	6.3	0.6%	4.7	0.4%	10.7	0.9%

Table C-30 Average real-time, offer-capped MW: 2008 to 2012

	2008		2009		2010		2011		2012	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	99	0.1%	158	0.2%	124	0.1%	197	0.2%	186	0.2%
Feb	92	0.1%	92	0.1%	117	0.1%	125	0.2%	1435	1.6%
Mar	117	0.2%	147	0.2%	216	0.3%	167	0.2%	812	1.0%
Apr	125	0.2%	151	0.2%	251	0.4%	267	0.4%	412	0.5%
May	59	0.1%	64	0.1%	337	0.5%	291	0.4%	400	0.5%
Jun	415	0.5%	103	0.1%	382	0.4%	330	0.4%	321	0.3%
Jul	202	0.2%	74	0.1%	473	0.5%	436	0.4%	451	0.4%
Aug	99	0.1%	137	0.2%	253	0.3%	245	0.3%	361	0.4%
Sep	182	0.2%	95	0.1%	378	0.5%	436	0.5%	705	0.8%
Oct	177	0.3%	105	0.2%	345	0.5%	319	0.4%	798	1.0%
Nov	157	0.2%	60	0.1%	382	0.5%	324	0.4%	955	1.1%
Dec	211	0.3%	128	0.2%	538	0.6%	330	0.4%	1546	1.8%

In order to help understand the frequency of offer capping in more detail, Table C-31 through Table C-35 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 2008 through 2012.

Table C-31 Offer-capped unit statistics: 2008

	2008 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	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-32 Offer-capped unit statistics: 2009

	2009 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	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table C-33 Offer-capped unit statistics: 2010

	2010 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%	2	0	0	0	1	13
80% and < 90%	0	2	1	7	8	13
75% and < 80%	0	0	0	0	3	7
70% and < 75%	3	0	0	0	4	13
60% and < 70%	0	1	1	1	0	34
50% and < 60%	1	0	0	5	0	22
25% and < 50%	4	2	4	9	17	41
10% and < 25%	2	0	0	4	2	37

Table C-34 Offer-capped unit statistics: 2011

	2011 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	6	9	4
80% and < 90%	0	0	1	2	5	9
75% and < 80%	0	0	0	0	3	3
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	1	0	1	1	20
50% and < 60%	0	0	0	2	13	23
25% and < 50%	2	0	0	5	19	70
10% and < 25%	9	2	0	0	2	49

Table C-35 Offer-capped unit statistics: 2012

	2012 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	2	0	1	1	1
80% and < 90%	0	1	0	0	2	4
75% and < 80%	0	0	0	0	1	2
70% and < 75%	0	0	0	0	1	2
60% and < 70%	1	0	0	1	1	8
50% and < 60%	7	0	1	0	1	10
25% and < 50%	5	1	1	2	8	49
10% and < 25%	6	0	0	3	13	58

Local Energy Market Structure: TPS Results

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint.

The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2012, through December 31, 2012. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

This appendix provides data on the TPS tests that were applied in PJM control zones that had congestion from one or more constraints for 100 or more hours. In 2012, the AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, PECO, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for 2012, actual competitive conditions associated with each of these frequently binding constraints were analyzed for the Real Time Energy Market.[1] The AECO, AEP, DAY, JCPL, Met-Ed, PPL, PENELEC, and RECO Control Zones were not affected by constraints binding for 100 or more hours. Information is provided, by qualifying zone, for each constraint including the number of tests applied, the number of tests that could have resulted in offer capping and the number of tests that did result in offer capping.[2] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

AP Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the AP Control Zone. Table D-1 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing.

Table D-2 shows the total tests applied for the constraint in the AP Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results

Table D-1 Three pivotal supplier test details for constraints located in the AP Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Garretts Run - Kiski Valley	Peak	20	36	2	0	2
	Off Peak	9	18	2	0	2

Table D-2 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the AP Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Garretts Run - Kiski Valley	Peak	2,405	10	0%	0	0%	0%
	Off Peak	533	2	0%	0	0%	0%

1 See the *Technical Reference for PJM Markets*, Section 8, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.
2 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-2 shows that none of the tests applied to the 'Garretts Run - Kiski Valley' constraint in the AP Zone resulted in offer capping.

ATSI Control Zone Results

In 2012, there was only one constraint in the ATSI Control Zone that occurred for more than 100 hours. Table D-3 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. Table D-3 shows that on an average, there was only one owner with available supply on peak and one owner off peak for the Lemoyne – Bowling Green line. The three pivotal supplier test results reflect this, as all tests were failed.

Table D-4 shows the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and those tests that did result in offer capping for the Lemoyne – Bowling Green line in the ATSI zone. None of the 569 tests applied to offline, uncommitted units that were eligible for offer capping on peak. None of the tests resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-3 Three pivotal supplier test details for constraints located in the ATSI Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Lemoyne - Bowling Green	Peak	10	6	1	0	1
	Off Peak	4	4	1	0	1

Table D-4 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ATSI Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Lemoyne - Bowling Green	Peak	569	0	0%	0	0%	0%
	Off Peak	4	0	0%	0	0%	0%

BGE Control Zone Results

In 2012, there were three constraints that occurred for more than 100 hours in the BGE Control Zone. Table D-5 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. Table D-5 shows that for two of the three constraints, there were ten owners, on an average, with available supply to relieve the constraint, both on peak and off peak.

Table D-6 shows the total tests applied for the three constraints in the BGE Zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-6 shows that one percent or fewer of the tests applied to the three constraints in the BGE zone could have resulted in offer capping and that one percent or fewer of their tests resulted in offer capping.

Table D-5 Three pivotal supplier test details for constraints located in the BGE Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Conastone - Otter	Peak	71	127	11	4	7
	Off Peak	58	106	10	3	7
Graceton - Raphael Road	Peak	59	110	10	3	7
	Off Peak	52	94	10	3	7
Northwest	Peak	64	100	10	2	8
	Off Peak	67	101	10	2	8

Table D-6 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the BGE Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Conastone - Otter	Peak	2,490	21	1%	2	0%	10%
	Off Peak	2,625	18	1%	2	0%	11%
Graceton - Raphael Road	Peak	9,521	86	1%	11	0%	13%
	Off Peak	10,997	65	1%	5	0%	8%
Northwest	Peak	9,946	68	1%	8	0%	12%
	Off Peak	4,484	35	1%	2	0%	6%

ComEd Control Zone Results

In 2012, there were four constraints that occurred for more than 100 hours in the ComEd Control Zone. Table D-7 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was three or less for all four constraints.

Table D-8 shows the total tests applied for the four constraints in the ComEd zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-7 Three pivotal supplier test details for constraints located in the ComEd Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Belvidere - Woodstock	Peak	12	10	2	0	2
	Off Peak	10	8	2	0	2
Dixon - Stillman Valley	Peak	23	18	2	0	2
	Off Peak	16	10	2	0	2
Mazon - Mazon	Peak	10	16	2	0	2
	Off Peak	8	15	2	0	2
Nelson - Cordova	Peak	39	34	3	0	3
	Off Peak	29	28	2	0	2

Table D-8 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the ComEd Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Belvidere - Woodstock	Peak	8,229	2	0%	1	0%	50%
	Off Peak	8,401	3	0%	0	0%	0%
Dixon - Stillman Valley	Peak	1,871	2	0%	2	0%	100%
	Off Peak	716	0	0%	0	0%	0%
Mazon - Mazon	Peak	1,008	0	0%	0	0%	0%
	Off Peak	352	0	0%	0	0%	0%
Nelson - Cordova	Peak	1,222	4	0%	0	0%	0%
	Off Peak	1,209	0	0%	0	0%	0%

DEOK Control Zone Results

In 2012, there was only one constraint that occurred for more than 100 hours in the DEOK Control Zone. Table D-9 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing.

Table D-10 shows the total tests applied for the 'Todd Hunter-Trenton' constraint in the DEOK zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. None of the tests that were applied to the constraint resulted in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped.

Table D-9 Three pivotal supplier test details for constraints located in the DEOK Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Todd Hunter - Trenton	Peak	19	10	1	0	1
	Off Peak	14	10	1	0	1

Table D-10 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DEOK Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Todd Hunter - Trenton	Peak	1,579	0	0%	0	0%	0%
	Off Peak	985	0	0%	0	0%	0%

DLCO Control Zone Results

In 2012, there was only one constraint that occurred for more than 100 hours in the DLCO Control Zone. Table D-11 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was one on peak and two off peak for the 'Brunot Island – Montour' constraint.

Table D-12 shows the total tests applied for the 'Brunot Island – Montour' constraint in the DLCO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-12 shows that only 4 of the 8,180 applied tests could have resulted in offer capping and none of those tests resulted in offer capping.

Table D-11 Three pivotal supplier test details for constraints located in the DLCO Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunot Island - Montour	Peak	19	35	1	0	1
	Off Peak	25	33	2	0	2

Table D-12 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DLCO Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Brunot Island - Montour	Peak	5,063	1	0%	0	0%	0%
	Off Peak	3,117	3	0%	0	0%	0%

Dominion Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the Dominion Control Zone. Table D-13 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. The average number of owners with available supply was three or fewer for both the constraints.

Table D-14 shows the total tests applied for the five constraints in the Dominion zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-14 shows that one percent or fewer of the tests applied to the two constraints in the Dominion Zone could have resulted in offer capping.

Table D-13 Three pivotal supplier test details for constraints located in the Dominion Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	9	10	1	0	1
	Off Peak	11	10	1	0	1
Clover	Peak	93	155	2	0	2
	Off Peak	92	158	3	0	2

Table D-14 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Dominion Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Beechwood - Kerr Dam	Peak	2,462	0	0%	0	0%	0%
	Off Peak	447	0	0%	0	0%	0%
Clover	Peak	12,359	94	1%	38	0%	40%
	Off Peak	4,887	43	1%	11	0%	26%

DPL Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the DPL Control Zone. Table D-15 shows the average constraint relief required on each constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing. The average number of owners with available supply was one on peak and off peak for both of the constraints.

Table D-16 shows the total tests applied for the two constraints in the DPL zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-16 shows that only 4 of the 7,620 applied tests for the 'Kenney – Stockton' constraint could have resulted in offer capping and all of those tests resulted in offer capping.

Table D-15 Three pivotal supplier test details for constraints located in the DPL Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Kenney - Stockton	Peak	42	48	1	0	1
	Off Peak	21	24	1	0	1
Mardela - Vienna	Peak	38	40	1	0	1
	Off Peak	25	27	1	0	1

Table D-16 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the DPL Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Kenney - Stockton	Peak	4,521	3	0%	3	0%	100%
	Off Peak	3,099	1	0%	1	0%	100%
Mardela - Vienna	Peak	2,514	16	1%	12	0%	75%
	Off Peak	849	7	1%	7	1%	100%

Table D-17 Three pivotal supplier test details for constraints located in the PECO Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Emilie	Peak	57	111	1	0	1
	Off Peak	43	107	1	0	1

Table D-18 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PECO Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Emilie	Peak	1,366	1	0%	0	0%	0%
	Off Peak	1,140	0	0%	0	0%	0%

PECO Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the PECO Control Zone. Table D-17 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For the constraint at Emilie, on an average, there was only one owner with available supply to relieve the constraint.

Table D-18 shows the total tests applied for the constraint in the PECO zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-18 shows that only one of the tests applied to the constraint in the PECO Zone could have resulted in offer capping.

Pepco Control Zone Results

In 2012, there was one constraint that occurred for more than 100 hours in the Pepco Control Zone. Table D-19 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. On an average, there was only one owner with available supply to relieve the constraint.

Table D-20 shows the total tests applied for the 'Buzzard – Ritchie' constraint in the Pepco zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-20 shows that only one of the tests applied to the constraint in the Pepco zone could have resulted in offer capping.

Table D-19 Three pivotal supplier test details for constraints located in the Pepco Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buzzard - Ritchie	Peak	31	36	1	0	1
	Off Peak	10	34	1	0	1

Table D-20 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the Pepco Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Buzzard - Ritchie	Peak	3,374	1	0%	1	0%	100%
	Off Peak	266	0	0%	0	0%	0%

PSEG Control Zone Results

In 2012, there were two constraints that occurred for more than 100 hours in the PSEG Control Zone. Table D-21 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owner passing and failing. For both of the constraints, the average number of owners with available supply was three or less.

Table D-22 shows the total tests applied for the two constraints in the PSEG zone, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The results reflect the fact that units that are already running cannot be offer capped. Only uncommitted units, which would be started to provide constraint relief, are eligible to be offer capped. Table D-22 shows that two percent or fewer of the tests applied to the two constraints in the PSEG zone could have resulted in offer capping. The Hillsdale – New Milford constraint had only 24 of its 5,603 applied tests that could have resulted in offer capping. Only 15 of the 5,603 applied tests did result in offer capping.

Table D-21 Three pivotal supplier test details for constraints located in the PSEG Control Zone: 2012

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Hillsdale - New Milford	Peak	28	49	2	0	2
	Off Peak	26	57	2	0	2
Leonia - New Milford	Peak	35	45	3	0	3
	Off Peak	26	54	2	0	2

Table D-22 Summary of three pivotal supplier tests applied to uncommitted units for constraints located in the PSEG Control Zone: 2012

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Hillsdale - New Milford	Peak	3,172	23	1%	15	0%	65%
	Off Peak	2,431	1	0%	0	0%	0%
Leonia - New Milford	Peak	993	15	2%	12	1%	80%
	Off Peak	1,391	24	2%	24	2%	100%

Interchange Transactions

Submitting Transactions into PJM

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.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Same-Time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.[1]

Real-Time Market

Market participants that wish to transact energy into, out of, or through PJM in the Real-Time Energy Market are required to make their requests to PJM via the NERC Interchange Transaction Tag (NERC Tag). PJM's Enhanced Energy Scheduler (EES) software interfaces with NERC Tags to create an interface that both PJM market participants and PJM can use to evaluate and manage external transactions that affect the PJM RTO.

All PJM interchange transactions are required to be at least 45 minutes in duration. However, PJM system operators may make adjustments that cause a transaction or interval(s) of the transaction to violate this minimum duration.

Scheduling Requirements

External offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply (aggregate offer). Schedules are submitted to PJM by submitting a valid NERC Tag.

Specific timing requirements apply for the submission of schedules. Schedules can be submitted up to 20 minutes prior to the scheduled start time for hourly transactions. Schedules can be submitted up to 4 hours prior to the scheduled start time for transactions that are more than 24 hours in duration. For a schedule to be included in PJM's day-ahead checkout process, the NERC Tag must be approved by all entities who have approval rights, and be in a status of "Implemented", by 1400 (EPT) one day prior to start of schedule. Schedules utilizing the Real-Time with Price option, also known as dispatchable schedules, must be submitted prior to 1200 noon (EPT) the day prior to the scheduled start time. Schedules utilizing firm point-to-point transmission service must be submitted by 1000 (EPT) one day prior to start of schedule. Transactions utilizing firm point-to-point transmission submitted after 1000 (EPT) one day prior will be accommodated if practicable.

Acquiring Ramp

PJM allows market participants to reserve ramp while they complete their scheduling responsibilities. The ramp reservation is validated against the submitted NERC Tag to ensure the energy profile and path matches. Upon submission of a ramp reservation request, if PJM verifies ramp availability, the ramp reservation will move into a status of "Pending Tag" which means that it is a valid reservation that can be associated with a NERC Tag to complete the scheduling process.

Specific timing requirements apply for the submission of ramp reservations. Ramp reservations can be made up to 30 minutes prior to the scheduled start time for hourly transactions. Ramp reservations can be made up to 4 hours prior to start time for transactions that are more than 24 hours in duration. Ramp reservations utilizing the Real-Time with Price option must be made prior to 1200 noon (EPT) the day prior to the scheduled start time. Ramp reservations expire if they are not used.

Acquiring Transmission

All external transaction requests require a confirmed transmission reservation from the PJM OASIS.[2] Due to ramp limitations, PJM may require market participants to shift their transaction requests. If the market participant shifts the request up to one hour in either direction, they are not required to purchase additional transmission. If the market participant chooses to fix a ramp violation

1 The material in this section is based in part on PJM Manual M-41: Managing Interchange. See PJM. "M-41: Managing Interchange", Revision 04 (December 3, 2012).

2 For additional details see PJM. "*PJM Regional Practices document*," <http://oasis.pjm.com>.

by extending the duration of the transaction, they do not have to purchase additional transmission if the total MWh capacity of the transmission request is not exceeded, and the transaction does not extend beyond one hour prior to the start, or one hour past the end time of the transmission reservation.

Transmission Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times.
- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.
- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available for periods ranging from one hour to one month.
- **Spot Import.** The spot import service is an option for non-load serving entities to offer into the PJM spot market at the interface as price takers. Prior to April 2007, PJM did not limit spot import service. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is PJM, the source would initially default to TVA's Interface Pricing point (SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is TVA, the sink would initially default to TVA's Interface Pricing point (SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus, hub or aggregate in the PJM footprint where LMP is calculated.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is TVA and the POD is NYIS, the source would initially default to TVA's Interface Pricing point (SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Real-Time Market Schedule Submission

Market participants enter schedules in PJM by submitting a valid NERC Tag. A NERC Tag can be submitted without a ramp reservation. When EES detects a NERC Tag that has been submitted without a ramp reservation, it will create a ramp reservation which will be evaluated against ramp, and approved or denied based on available ramp room at the time the NERC Tag is submitted.

Real-Time with Price Schedule Submission

Real-Time with Price schedules, also known as dispatchable schedules, differ from other schedules. To enter a Real-Time with Price schedule, the market participant must first make a ramp reservation in EES specifying "Real-Time with Price" and must enter a price associated with each energy block. Upon submission, the Real-Time with Price request will automatically move to the "Pending Tag" status, as Real-Time with Price schedules do not hold ramp. Once the information is entered in EES, a NERC Tag must be submitted with the ramp reservation associated on the NERC Tag. Upon implementation of the NERC Tag, PJM will curtail the tag to 0 MW. During the operating day, if the dispatchable transaction is to be loaded, PJM will then reload the tag. The process of issuing curtailments and reloading the tag continues through the operating day as the economics of the system dictate.

Dynamic Schedule Requirements

An entity that owns or controls a generating resource in the PJM Region may request that all or part of the generating resource's output be removed from the PJM Region, via dynamic scheduling of the output, to a load outside the PJM Region. An entity that owns or controls a generating resource outside of the PJM Region may request that all or part of the generating resource's output be added to the PJM Region, via dynamic scheduling of the output, to a load inside the PJM Region. Due to the complexity of these arrangements, requesting entities must coordinate with PJM and complete several steps before a dynamic schedule can be implemented. The requesting entity is responsible for submitting a dynamic NERC Tag to match the scheduled output of the generating resource.

Real-Time Evaluation and Checkout

PJM conducts an hourly checkout with each adjacent balancing authority using both the electronic approval of schedules and telephone calls. Once the tag has been approved by all parties with approval rights, the tag status moves to an "Implemented" status, and the schedule is ready for the adjacent balancing authority checkout.

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. Both balancing authorities must enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy flows between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, performs a least cost economic dispatch solution, and accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Real-Time with Price Evaluation and Checkout

Real-time with price schedules, also known as dispatchable schedules, are evaluated hourly to determine whether or not they will be loaded for the upcoming hour. Since real-time with price schedules do not hold ramp room, there may be times when the schedule is economic but will not be loaded because ramp is not available.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

Dispatchable transactions will be curtailed if the system operator does not believe that the transaction will be economic for the next hour. Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink. Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero. All self curtailments must be requested on 15 minute intervals and will be approved only if there is available ramp.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[3]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state. Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.
- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.
- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.
- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.
- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.
- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR

3 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed January 16, 2013) <http://www.nerc.com/files/IRO-006-4.pdf>.

3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.
- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.
- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table E-1 shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Day-Ahead Market

For Day-Ahead Market scheduling, EES serves only as an interface to the eMarket application. Day-Ahead Market transactions are evaluated in the Day-Ahead Market, and the results sent to EES. No checkout is performed on Day-Ahead Market schedules as they are considered financially binding transactions and not physical schedules.

Submitting Day-Ahead Market Schedules

Market participants can submit Day-Ahead Market schedules to the eMarket application through EES. These schedules do not require a NERC Tag, as they are not physical schedules for actual flow. Day-Ahead Market schedules require an OASIS number to be associated upon submission.[4] The path is identified on the OASIS reservation. In addition to the selection of OASIS and pricing points, the market participant must enter their energy profile. "Fixed" act as a price taker, "dispatchable" set a floor or ceiling price criteria for acceptance and "up-to" set the maximum amount of congestion the market participant is willing to pay.

4 On September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additionally, effective May 15, 2012, up-to congestion transactions were required to be submitted for the PJM Day-Ahead Market evaluation in the eMarket application, and are no longer accepted through the EES application. Additional details can be found under the "Up-to Congestion" heading in *Section 4: Interchange Transactions* of this report.

Table E-1 TLRs by level and reliability coordinator: 2004 through 2012

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097
2010	ICTE	72	25	149	50	30	0	326
	MISO	123	93	0	15	18	0	249
	NYIS	104	0	0	0	0	0	104
	ONT	94	5	0	1	0	0	100
	PJM	65	45	0	0	0	0	110
	SWPP	244	1,049	19	63	32	0	1,407
	TVA	37	64	8	1	6	0	116
	VACS	1	1	0	0	0	0	2
Total		740	1,282	176	130	86	0	2,414
2011	ICTE	23	12	123	54	48	0	260
	MISO	92	30	1	9	9	0	141
	NYIS	161	0	0	0	0	0	161
	ONT	88	0	0	0	0	0	88
	PJM	34	28	0	0	0	0	62
	SWPP	292	298	1	25	22	0	638
	TVA	75	99	9	2	15	0	200
	VACS	9	3	0	0	0	0	12
Total		774	470	134	90	94	0	1,562
2012	ICTE	25	7	11	63	40	0	146
	MISO	75	26	0	16	42	0	159
	NYIS	60	0	0	0	0	0	60
	ONT	47	1	0	0	0	0	48
	PJM	18	19	0	0	0	0	37
	SOCO	0	1	0	0	0	0	1
	SWPP	248	165	5	78	33	0	529
	TVA	55	32	9	7	5	0	108
	VACS	6	4	0	0	0	0	10
Total		534	255	25	164	120	0	1,098

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the 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 important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[5]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.6 The NYISO requires hourly bids or offer prices for each export or import transaction and clears

5 See also the discussion of these issues in the 2005 State of the Market Report, *Section 4, "Interchange Transactions"* (March 8, 2006).

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

its market for each hour based on hourly bids.[7] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the 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 the NYISO and the time when participants are notified that they have cleared. The lag is a result 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 the NYISO's RTC timing, market participants must submit bids or offers by no later 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 the 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, in the Real-Time 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.[8] The duration of the requested transaction can vary from 45 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, less than 1 percent of all transactions submit an associated 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. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the 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.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the 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 NERC Tag, an OASIS reservation 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 the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. 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 FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[9] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[10] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[11] PJM continued to operate under the terms of the protocol through 2012.

7 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 16, 2013) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

8 See PJM. "Manual 41: Managing Interchange" (December 3, 2012) (Accessed January 16, 2013) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

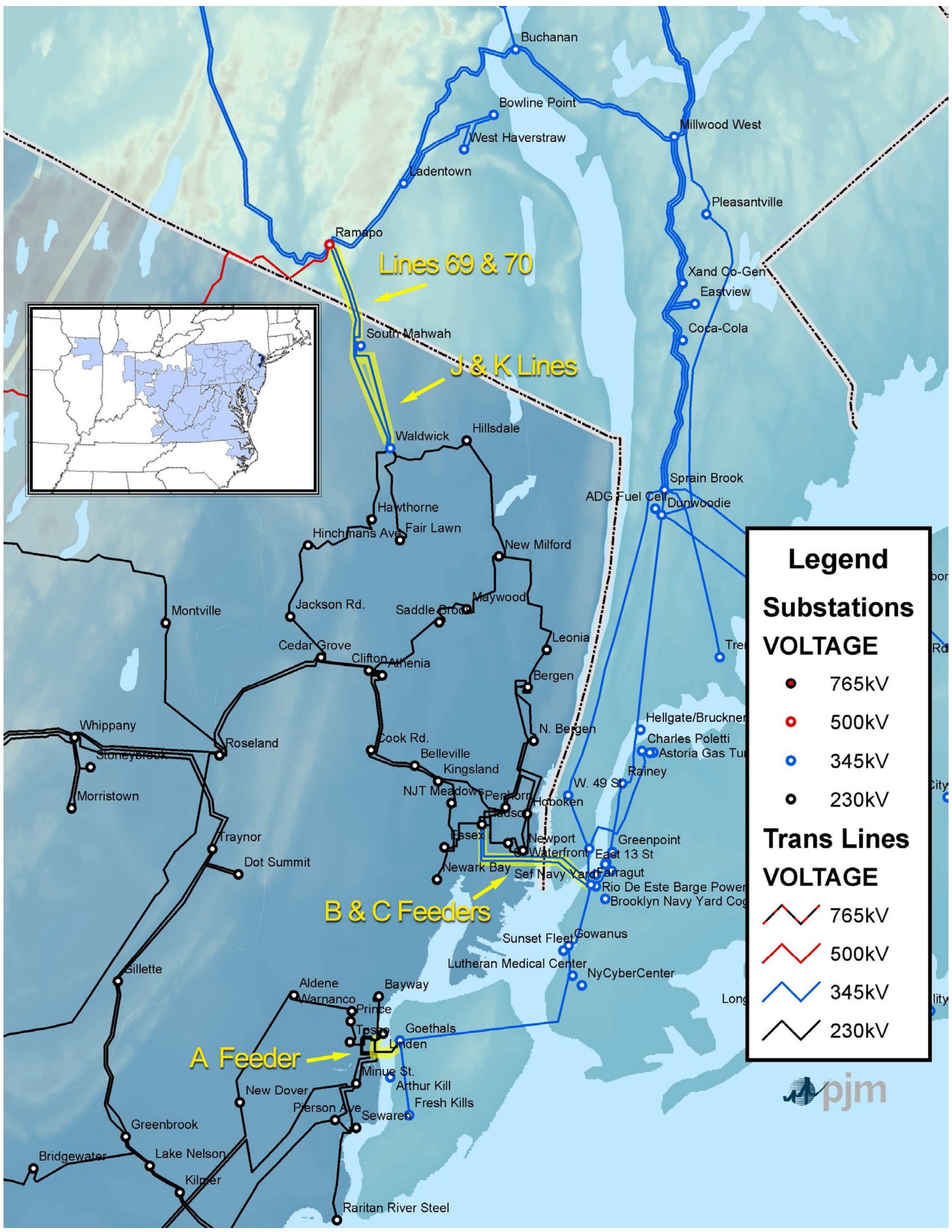
9 111 FERC ¶ 61,228 (2005).

10 "Protest of the Consolidated Edison Company of New York, Inc.," Protest, Docket No. EL02-23-000 (January 30, 2006).

11 120 FERC ¶ 61,161

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 wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City (Figure E-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 under delivered on the agreements and asked the FERC to resolve the issue.

Figure E-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 to address the issues raised by Con Edison.[12] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in 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 costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs 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 FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2012, PSE&G's revenues were greater than its congestion charges by $80,727 after adjustments (PSE&G's revenues were greater than its congestion charges by $778,879 in 2011.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2012, Con Edison's congestion credits were $3,627,462 less than its day-ahead congestion charges (Credits had been $2,319,278 less than charges in 2011). Table E-2 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.[13]

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 -$42,203 in 2012. The parties should address this issue.

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. This occurred in 7.7 percent of the hours in 2012.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.14 By order issued September 16, 2010, the Commission approved this settlement,15 which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.16 The settlement defined ConEd's cost responsibility for

12 111 FERC ¶ 61,228 (2005).

13 *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 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

14 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

15 132 FERC ¶ 61,221.

16 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).

upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.17 ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table E-2 below reflecting those charges effective May 1, 2012.

Table E-2 Con Edison and PSE&G wheel settlements data: 2012

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$31,655	($38)	$31,616	$96,054	$0	$96,054
	Congestion Credit			$5,700			$73,645
	Adjustments			$87			($754)
	Net Charge			$25,829			$23,163
February	Congestion Charge	$40,795	($570)	$40,225	$124,704	$0	$124,704
	Congestion Credit			$7,888			$90,497
	Adjustments			$0			($1,037)
	Net Charge			$32,337			$35,244
March	Congestion Charge	$212,620	$310	$212,930	$323,108	$0	$323,108
	Congestion Credit			$74,365			$293,945
	Adjustments			$0			($1,121)
	Net Charge			$138,564			$30,284
April	Congestion Charge	$157,737	$54,006	$211,743	$321,351	$0	$321,351
	Congestion Credit			$18,543			$205,689
	Adjustments			($7,769)			($3,046)
	Net Charge			$200,969			$118,708
May	Congestion Charge	$1,425,238	($615)	$1,424,623	$0	$0	$0
	Congestion Credit			$0			$289,527
	Adjustments and Transmission Charges			($2,775,525)			($37)
	Net Charge			$4,200,148			($289,490)
June	Congestion Charge	$353,769	$67,757	$421,526	$0	$0	$0
	Congestion Credit			$312,781			$0
	Adjustments and Transmission Charges			($2,773,835)			$0
	Net Charge			$2,882,580			$0
July	Congestion Charge	$93,567	$0	$93,567	$0	$0	$0
	Congestion Credit			$63,666			$0
	Adjustments and Transmission Charges			($2,994,092)			($1,382)
	Net Charge			$3,023,992			$1,382

17 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion Charge	$12,757	$0	$12,757	$0	$0	$0
	Congestion Credit			$8,838			$0
	Adjustments and Transmission Charges			($2,943,519)			$0
	Net Charge			$2,947,438			$0
September	Congestion Charge	$1,868,692	$114,181	$1,982,873	$0	$0	$0
	Congestion Credit			$782,643			$0
	Adjustments and Transmission Charges			($2,798,578)			$8
	Net Charge			$3,998,807			($8)
October	Congestion Charge	$678,251	($132,724)	$545,527	$0	$0	$0
	Congestion Credit			$226,409			$0
	Adjustments and Transmission Charges			($2,890,254)			$3
	Net Charge			$3,209,372			($3)
November	Congestion Charge	$169,407	$11,637	$181,044	$0	$0	$0
	Congestion Credit			$133,786			$0
	Adjustments and Transmission Charges			($2,849,659)			$3
	Net Charge			$2,896,917			($3)
December	Congestion Charge	$678,112	($9,239)	$668,874	$0	$0	$0
	Congestion Credit			$460,517			$0
	Adjustments and Transmission Charges			($3,116,156)			$4
	Net Charge			$3,324,512			($4)
Total	Congestion Charge	$5,722,599	$104,705	$5,827,303	$865,217	$0	$865,217
	Congestion Credit			$2,095,137			$953,303
	Adjustments and Transmission Charges			($23,149,300)			($7,358)
	Net Charge			$26,881,466			($80,727)

Ancillary Service Markets

This appendix covers three areas related to Ancillary Service Markets: area control error, the details of regulation availability and price determination, and the clearing process for the Synchronized Reserve Market.

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]

On October 1, 2012, PJM implemented Performance Regulation in response to FERC Order 755 to promote new sources and types of regulation which offer lower MW capabilities but faster and more accurate response to the PJM regulation signal. PJM now measures the performance of each regulating resource at 10 second intervals combining the results into an hourly performance score. The performance score is then used in the calculation of settlement credits. Hourly performance scores are also saved to create a 100-hour rolling performance score which is used calculate an effective performance offer and capability offer from a resource's actual performance offer and capability offer during market clearance and in satisfying the regulation requirement. The performance score is calculated as a function of three distinct measurements performed against the unit's response to the regulation signal. The measurements are correlation, delay, and precision.[3]

Resources wishing to participate in the Regulation Market must pass three consecutive certification tests. 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 their regulation signal (RegA or RegD) with a score of 75 percent or better. If a resource has its historic performance score fall below 40 percent for a signal type, that resource becomes ineligible to offer regulation in that signal type and must re-certify in that signal type before offering regulation in that signal type again.[4]

Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL)

- Control Performance Standard 1 (CPS1) and Balancing Authority Ace Limit (BAAL) are standard metrics used to measure and report the effectiveness of ACE control. The purpose of the CPS1/BAAL standards 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.** CPS1 is a statistical measure of ACE variability and its relationship to frequency error. It is measured each minute. It is intended to provide a frequency-sensitive evaluation of how well PJM meets its demand requirements with its supply resources. The maximum CPS1 score is 200 percent. This is achieved when either the frequency error is zero or the ACE is zero. The minimum passing score is 100 percent monthly.

1 The PJM Manuals define ACE: "Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts. Two additional terms may be included in ACE under certain conditions--the time error bias term and PJM dispatcher adjustment term (manual add). These provide for automatic inadvertent interchange payback and error compensation, respectively." PJM. "Manual 12: Balancing Operations," Revision 27 (December 20, 2012), para. 3.1.1, "PJM Area Control Error" p. 12.

2 Regulation Market business rules are defined in PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 57 (December 1, 2012), pp. 52-66.

3 A full specification for each of these measurements is in PJM M-12 "Balancing Operations," Rev 27 (December 20, 2012), para. 4.5.6 pp 52-54.

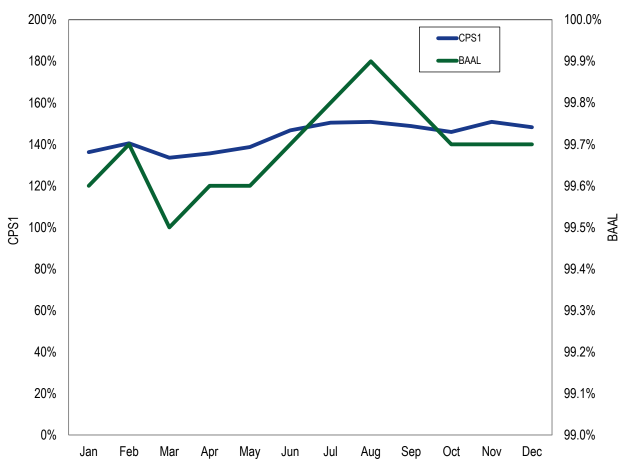
4 See "Manual 12: Balancing Operations," Revision 27 (December 20, 2012), Section 4.5.5, pg. 51.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which establishes a new metric, balancing authority ACE limit (BAAL). PJM counts the total number of minutes that ACE complies with the BAAL limits (high and low) and divides it by the total number of minutes for a month, with a passing level for this goal being set at 99.0 percent for each month.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance for both CPS1 and BAAL metrics was acceptable throughout 2012. The regulation requirement was reduced in the last quarter of 2012 after the introduction of the new performance based Regulation Market. The requirement was reduced from one percent of the peak load forecast during on-peak hours and one percent of the valley load during off-peak hours to 0.7 percent of the peak load forecast during on-peak hours and 0.7 percent of the valley load during off-peak hours.

Figure F-1 PJM CPS1/BAAL performance: 2012



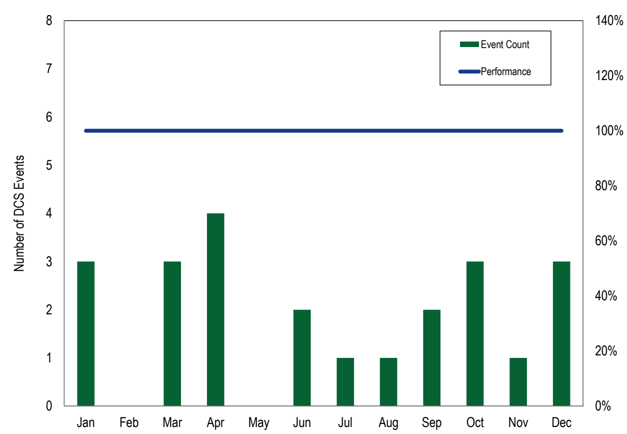
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 and BAAL standards requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load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

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[5] 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 1,000 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 23 DCS events during 2012 and successfully recovered from all of them. Recovery times ranged from five minutes to 19 minutes. Figure F-2 illustrates the event count by month. All of the events resulted in low ACE. The solution in all 23 events was to declare a spinning event.

Figure F-2 DCS event count and PJM performance (By month): 2012



Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as to keep the reportable metrics CPS1 and BAAL within acceptable limits. On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional

5 For more information on the NERC DCS, see "Standard BAL-002-0 – Disturbance Control Performance" (April 1, 2005) < www.nerc.com/files/BAL-002-0.pdf> (61 KB).

response regulation resources.[6] Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. Performance Based Regulation includes a new class of regulation resources capable of responding to a new, faster signal called RegD. Under the new performance based Regulation Market design, providers offer both regulation capability (MW) and regulation mileage per MW of capability (ΔMW/MW). The performance based Regulation Market is PJM's response to FERC Order No. 755.

Due to their varying characteristics, fast (Reg D following) and slow (Reg A following) resources are not perfect substitutes for one another for purposes of providing regulation as defined in PJM's market. But because regulation is a single product in PJM's market design, the clearing rules must account for and optimize the selection of fast and slow resources included in the market clearing.

Fast and slow resources, depending on technology type, have different cost structures, different sources, and different capabilities. Fast resources, for example, tend to be non-generation resources. Fast resources have quick response times but limited total response capability in one direction relative to slow resources. PJM has historically met its regulation requirements via the use of slow resources following a single regulation signal (RegA) designed to reflect the characteristics of slow resources in meeting ACE and frequency control requirements. Although fast resources can respond quickly to changes in RegA, they cannot always successfully track the RegA signal. When RegA is negative or positive for a significant period of time, non-generator, fast response units, such as fly wheels and batteries, quickly exhaust their capability to follow the signal. When RegA has many small displacements and crosses zero often, non-generator fast response units can more closely track RegA than traditional slow resources.

Generally speaking, fast response units are better suited to follow a signal that makes frequent changes from negative to positive and slow resources are better suited to follow a signal that makes less frequent changes from negative to positive. Regulation service defined around only one signal cannot take full advantage of the capability that either fast or slow resources can provide. A signal designed to take advantage of a particular resource type (fast or slow), will tend to diminish the ability of the other resource type to contribute to ACE and frequency control.

Due to the nature of the Regulation Market in PJM it is possible to meet PJM's regulation requirements (the regulation performance target) entirely with slow resources following RegA. PJM cannot, however, meet its regulation requirements (regulation performance target) using only fast resources, even with a fast resource specific regulation signal (RegD).

Although PJM cannot replace its slow regulation fleet with a fast regulation fleet, the KEMA Study indicated that a combination of fast and slow resources, following separate fast (RegD) and slow (RegA) regulation signals, could do a more effective job of meeting PJM's regulation requirement (regulation performance target) than slow resources alone. According to the study, the smaller the proportion of fast regulation MW and the greater the proportion of slow regulation used, the more benefit there is to substituting fast regulation MW for slow regulation MW. In other words, the smaller the proportion of fast regulation used, the more slow regulation each MW of fast regulation can replace. Conversely, as the proportion of fast resources increases, the benefit of substituting fast capability for slow capability in meeting a specific regulation performance target decreases. In other words, the larger the proportion of fast regulation used, the less slow regulation each MW of fast regulation can replace. This is not surprising and follows a normal diminishing returns pattern. This relationship is the benefits factor, or rate of substitution, between fast and slow resources. The benefits factor decreases as the amount of fast resources increases.

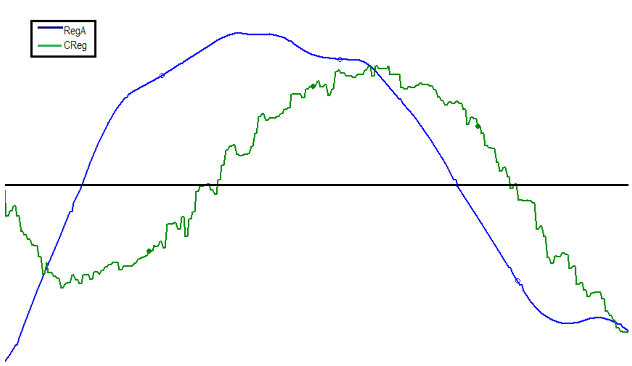
The KEMA Study indicated that, for a given regulation performance target, there is a limit to this ability to substitute fast for slow regulation MW and reduce total combined regulation MW when trying to achieve a specific regulation performance target. This is why PJM cannot entirely replace its slow regulation fleet following a RegA signal with a fast regulation fleet following a RegD signal. Although the rate of substitution is greater than 1.0 when the level of fast

6 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").

regulation is low (one MW of fast can replace more than one MW of slow while holding regulation performance target constant), the rate of substitution falls as more fast regulation MW are added. The rate of substitution is the marginal benefits factor. Eventually, the addition of another MW of fast capability actually requires adding rather than replacing MW of slow capability to maintain a regulation performance target. At this point the rate of substitution is negative (less than zero) and the addition of fast resources makes it harder to maintain a regulation performance target. PJM's current implementation prevents the rate of substitution (the benefits factor) from falling below zero. While this is incorrect, it is unlikely to have any practical effect as the price of fast resources is likely to be very high under those conditions.

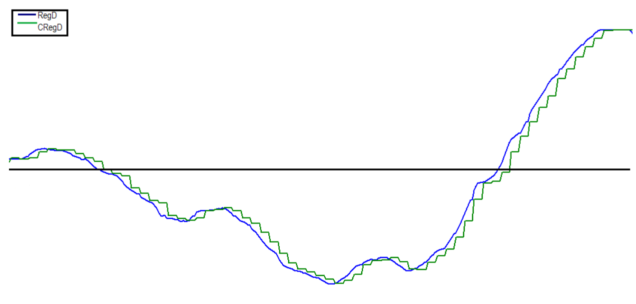
Reg A is a signal developed by PJM to moderate ACE. It is designed for the class of regulating resources able to begin responding to change in output and respond fully within five minutes to their full regulating capability. This signal is generally developed for steam, and CC units, with between a few percent up to 25 percent of hydro regulation. Figure F-3 shows a screenshot of typical 10-minute time period of PJM's RegA signal and CReg compliance signal.

Figure F-3 PJM RegA signal and CReg compliance signal. Screenshot of typical 10-minute time period



RegD is a regulation signal developed by PJM designed to moderate ACE. It is designed for the class of regulating units that can respond within a few seconds and reach their full response capability within one to two minutes. It is designed for units that respond quickly and accurately but may not have high capability or capacity at full max or min for a full hour. Figure F-4 shows a screenshot of typical 10-minute time period of PJM's RegD signal and CReg compliance signal.

Figure F-4 PJM RegD signal and CRegD compliance signal. Screenshot of typical 10-minute time period



Regulation signals are designed for the purpose of moderating ACE. The design must account for the characteristics of the expected response. The design of the RegD signal to favor the attributes of fast regulation resources is part of the FERC Order 755 mandate. But ultimately the reason for regulation is to counteract ACE and both signals must be designed to accomplish that end. Even a very fast regulating unit will need to have some capacity and MW to help with ACE correction, and even a unit with a large MW capability must be able to react with some sensitivity and speed to help with ACE correction. The relationship between the two types of regulating resources is under constant review and the relationship between the two (expressed in the Benefits Factor) is subject to change.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capability price in $/MW at cost plus up to $12 adder daily into the Regulation Market using the PJM market user interface. Users must also enter the signal type they want to follow (RegA or RegD), their regulation capability in MW, as well as cost validation parameters - fuel cost, heat rate at economic maximum, heat rate at regulation minimum, and the VOM rate. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Owners may also enter price based offers up to a maximum of $100/MW. Demand resources are eligible to offer regulation and did so for the first time in November of 2011. Demand resources have an LOC of zero.

Under current 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 that are not set to "unavailable" for the day 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 the Ancillary Services Optimizer software (ASO) to determine the amount of Tier 2 synchronized reserve/non-synchronized reserve required, develop regulation and synchronized reserve supply curves, and assign regulation, synchronized reserve, and non-synchronized reserve to specific units. All regulation resource units which have made offers in the daily Regulation Market are evaluated by ASO for regulation. ASO excludes units according to the following ordered criteria: a) Daily or hourly unavailable status; 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 ASO 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 capability offer price is calculated using the sum of the unit's regulation cost-based offer (divided by the benefits factor of the resource type and the historic performance score of the resource) plus 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.[7] Based on this result, ASO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. ASO uses price-based offers for those operators not offer capped and re-solves. Unit assignments based on this solution are final. The final clearing price is not determined at the time of unit assignment.

The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared, prior to the hour, and supplementally within the hour, on a real time basis. The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared and priced interactively with the Energy Market and secondary reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements, reserve requirements and prior to the hour assignments for regulation and reserves. The final clearing prices are calculated at five-minute intervals based on the real time prices and LMPs of energy. These five-minute prices are averaged to arrive at the final hourly clearing price. This price is sent to Settlements and used and the basis for credits and charges.

- **Cleared Regulation.** Regulation actually assigned by ASO is cleared regulation. The capability and performance prices are calculated every five minutes by the Locational Pricing Calculator (LPC) with the final hourly clearing price averaged from the five minute prices. In real time, units that have been assigned regulation, synchronized reserve, and non-synchronized reserve are expected to

7 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" for a full discussion of opportunity costs.

provide regulation, synchronized reserve, and non-synchronized reserve for the designated hour.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW, or effective 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.

Synchronized Reserve Market Clearing

PJM's market clearing engines consider resources capable of providing Tier 2 synchronized reserve as being either flexible or inflexible. Flexible resources are those resources that are online, dispatchable, and have offers for Tier 2 synchronized reserve. Inflexible resources are either synchronous condensers or DSR. In the Mid-Atlantic Dominion Subzone, the following four steps occur to clear and price the market for Tier 2 synchronized reserve.

First, one hour before the market hour, ASO estimates the sum of the available Tier 1 synchronized reserve within the MAD Subzone and the available transfer capacity from outside the MAD Subzone. Next, ASO subtracts this estimate from the MAD Subzone synchronized reserve requirement to determine the amount of Tier 2 synchronized reserve needed to satisfy the requirement. Then, ASO generates a co-optimized solution for this amount of Tier 2 synchronized reserve. Finally, ASO logs the amount of Tier 2 synchronized reserve comprised of inflexible resources, commits these resources to provide Tier 2 synchronized reserve, and notifies these resources through eMKT. The amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Second, half an hour before the market hour, IT SCED performs the same functions as ASO up to the point of logging and committing individual resources, taking into account the amount of inflexible resources already committed by ASO. IT SCED, however, does not consider DSR in its solution. After IT SCED produces its solution, a PJM operator reviews the solution, calls the inflexible resources to commit them to provide Tier 2 synchronized reserve, and logs each resource separately. As with ASO, the amount of Tier 2 synchronized reserve provided by flexible resources is not logged and is not carried through to later steps in the clearing process.

Third, 15 minutes before each five-minute period in the market hour, RT SCED estimates the amount of needed Tier 2 synchronized reserve, taking into account the amount of inflexible resources already committed by ASO and IT SCED. RT SCED considers only flexible resources due to the notification-time requirements of inflexible resources. Once RT SCED generates its solution, RT SCED commits the resources from its solution and logs these resources.

Lastly, every five minutes within the market hour, LPC calculates market clearing prices by incorporating resource offers and LOC based on real-time LMP and marginal cost. LPC computes the price of one additional MW of Tier 2 synchronized based on these factors and the committed resources and uses this price as the within-hour five-minute clearing price. For the hour, the Synchronized Reserve Market Clearing Price is the simple average of the 12 five-minute clearing prices.

Whereas the hourly price is the average of the within-the-hour five-minute prices, the hourly cost (per MW) is the sum of credits for cleared and self-scheduled (and, prior to October 1, added out-of-market) synchronized reserve and credits for after-market lost opportunity cost divided by the total MW of synchronized reserve cleared and self-scheduled (and, prior to October 1, added out-of-market). Price is regularly less than cost, occasionally very close to cost, but never more than cost. PJM guarantees resources to be made whole to their offer plus opportunity costs.

Congestion and Marginal Losses

Locational Marginal Price (LMP) is the incremental price of energy at a bus. LMP at any bus is made up of three components: the system marginal price (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and transmission constraints. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the generation of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[1] Congestion results from physical limitations of elements of the transmission system to move power from point to point. Congestion costs reflect the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

LMP Components Real-Time and Day-Ahead

Table G-1 shows the components of real-time LMP from 2008 through 2012. Table G-2 compares 2011 real-time LMP components by zone to 2012 real-time LMP components by zone. Table G-3 compares 2011 real-time LMP components by hub to 2012 LMP components by hub. Table G-4 shows the components of day-ahead LMP from 2008 through 2012. Table G-5 compares 2011 day-ahead LMP components by zone to 2012 day-ahead LMP components by zone.

Table G-1 PJM real-time, average LMP components (Dollars per MWh): 2008 through 2012

Year	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03
2010	$44.83	$44.72	$0.07	$0.04
2011	$42.84	$42.77	$0.05	$0.02
2012	$33.11	$33.06	$0.04	$0.01

1 For additional information, see the *MMU Technical Reference for PJM Markets*, at, "Marginal Losses."

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

Table G-2 Zonal real-time, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.56	$42.77	$2.80	$1.99	$34.20	$33.06	($0.09)	$1.22
AEP	$39.04	$42.77	($2.41)	($1.32)	$31.70	$33.06	($0.59)	($0.77)
AP	$42.91	$42.77	$0.23	($0.09)	$33.08	$33.06	$0.09	($0.07)
ATSI	$39.24	$41.20	($1.79)	($0.17)	$32.61	$33.06	($0.64)	$0.18
BGE	$49.11	$42.77	$4.40	$1.93	$37.22	$33.06	$2.69	$1.47
ComEd	$33.30	$42.77	($6.92)	($2.55)	$29.25	$33.06	($2.23)	($1.58)
DAY	$39.22	$42.77	($2.81)	($0.74)	$32.35	$33.06	($0.74)	$0.02
DEOK	NA	NA	NA	NA	$30.91	$33.06	($0.65)	($1.51)
DLCO	$38.98	$42.77	($2.48)	($1.31)	$31.72	$33.06	($0.36)	($0.98)
Dominion	$46.38	$42.77	$3.02	$0.60	$34.69	$33.06	$1.26	$0.37
DPL	$47.33	$42.77	$2.32	$2.25	$36.15	$33.06	$1.64	$1.45
JCPL	$47.65	$42.77	$2.84	$2.04	$34.06	$33.06	($0.15)	$1.15
Met-Ed	$45.82	$42.77	$2.34	$0.72	$33.96	$33.06	$0.44	$0.46
PECO	$46.56	$42.77	$2.37	$1.42	$34.08	$33.06	$0.24	$0.77
PENELEC	$42.95	$42.77	($0.19)	$0.37	$33.50	$33.06	($0.10)	$0.54
Pepco	$47.34	$42.77	$3.44	$1.13	$36.33	$33.06	$2.38	$0.88
PPL	$45.84	$42.77	$2.42	$0.65	$33.40	$33.06	($0.13)	$0.46
PSEG	$48.17	$42.77	$3.30	$2.10	$34.79	$33.06	$0.48	$1.24
RECO	$44.28	$42.77	($0.37)	$1.88	$34.36	$33.06	$0.17	$1.13
PJM	$42.84	$42.77	$0.05	$0.02	$33.11	$33.06	$0.04	$0.01

Table G-3 Hub real-time, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$37.08	$42.77	($3.00)	($2.69)	$30.46	$33.06	($0.84)	($1.77)
AEP-DAY Hub	$38.55	$42.77	($2.69)	($1.52)	$31.55	$33.06	($0.67)	($0.84)
ATSI Gen Hub	$38.87	$41.19	($1.77)	($0.55)	$32.19	$33.06	($0.64)	($0.23)
Chicago Gen Hub	$32.25	$42.77	($7.41)	($3.10)	$28.28	$33.06	($2.73)	($2.05)
Chicago Hub	$33.48	$42.77	($6.78)	($2.51)	$29.43	$33.06	($2.11)	($1.52)
Dominion Hub	$45.84	$42.77	$2.87	$0.20	$34.19	$33.06	$1.04	$0.08
Eastern Hub	$47.71	$42.77	$2.48	$2.47	$36.55	$33.06	$1.91	$1.58
N Illinois Hub	$33.07	$42.77	($6.95)	($2.76)	$28.95	$33.06	($2.38)	($1.73)
New Jersey Hub	$47.88	$42.77	$3.08	$2.03	$34.45	$33.06	$0.19	$1.19
Ohio Hub	$38.58	$42.77	($2.73)	($1.45)	$31.66	$33.06	($0.64)	($0.76)
West Interface Hub	$40.57	$42.77	($1.21)	($0.99)	$32.50	$33.06	($0.04)	($0.52)
Western Hub	$43.56	$42.77	$0.88	($0.09)	$33.90	$33.06	$0.77	$0.07

Table G-4 PJM day-ahead, average LMP components (Dollars per MWh): 2008 through 2012

Year	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	$0.06	$0.09
2010	$44.57	$44.61	$0.03	($0.06)
2011	$42.52	$42.72	($0.07)	($0.13)
2012	$32.79	$32.72	$0.09	($0.01)

Table G-5 Zonal day-ahead, average LMP components (Dollars per MWh): 2011 and 2012

	2011				2012			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$47.86	$42.72	$2.84	$2.30	$34.36	$32.72	$0.28	$1.36
AEP	$39.32	$42.72	($1.93)	($1.47)	$31.45	$32.72	($0.37)	($0.90)
AP	$42.96	$42.72	$0.29	($0.05)	$32.82	$32.72	$0.14	($0.04)
ATSI	$39.34	$41.59	($1.37)	($0.88)	$32.11	$32.72	($0.55)	($0.07)
BGE	$48.66	$42.72	$3.69	$2.25	$36.91	$32.72	$2.42	$1.77
ComEd	$33.46	$42.72	($6.15)	($3.12)	$28.80	$32.72	($2.08)	($1.85)
DAY	$39.29	$42.72	($2.60)	($0.83)	$32.10	$32.72	($0.47)	($0.15)
DEOK	NA	NA	NA	NA	$30.73	$32.72	($0.33)	($1.66)
DLCO	$38.89	$42.72	($2.52)	($1.31)	$31.53	$32.72	($0.19)	($1.00)
Dominion	$46.00	$42.72	$2.61	$0.66	$34.39	$32.72	$1.18	$0.48
DPL	$47.93	$42.72	$2.61	$2.59	$35.86	$32.72	$1.30	$1.83
JCPL	$47.59	$42.72	$2.48	$2.38	$34.24	$32.72	$0.23	$1.29
Met-Ed	$45.82	$42.72	$2.37	$0.72	$33.68	$32.72	$0.37	$0.59
PECO	$47.21	$42.72	$2.71	$1.78	$34.02	$32.72	$0.37	$0.92
PENELEC	$42.79	$42.72	($0.17)	$0.24	$33.41	$32.72	$0.10	$0.59
Pepco	$47.58	$42.72	$3.35	$1.51	$36.05	$32.72	$2.12	$1.21
PPL	$45.68	$42.72	$2.37	$0.59	$33.19	$32.72	$0.03	$0.43
PSEG	$48.32	$42.72	$3.06	$2.53	$34.76	$32.72	$0.54	$1.49
RECO	$45.80	$42.72	$1.13	$1.95	$34.08	$32.72	$0.14	$1.22
PJM	$42.52	$42.72	($0.07)	($0.13)	$32.79	$32.72	$0.09	($0.01)

Congestion Costs

Zonal Congestion Costs

Day-ahead and balancing congestion costs within zones for 2011 and 2010 are presented in Table G-6 and Table G-7.[3] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear congestion costs. Load congestion payments, when positive, measure the congestion cost to load in an area. Load congestion payments, when negative, measure the congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the congestion credit to generation in an area. Generation congestion credits, when negative, measure the congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion. But the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The ComEd Control Zone, AEP Control Zone and the AP Control Zone are examples of how a positive net congestion bill can result from very different

3 The total zonal congestion numbers were calculated as of March 2, 2013 and are, based on continued PJM billing updates, subject to change. As of March 2, 2013, the total zonal congestion related numbers presented here differed from the March 2, 2013 PJM totals by $0.10 Million, a discrepancy of 0.02 percent (.00019).

combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $171.0 million, of any control zone in 2012. The positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. Thus, the lower prices in ComEd, which resulted from a lower congestion component of LMP, meant that load paid lower prices and lower congestion, and that generators received lower prices and a lower congestion component. The result was positive measured congestion costs. This somewhat counter intuitive result is the result of congestion accounting conventions.

The AEP Control Zone had the second highest congestion charges, $104.2 million, of any control zone in 2012. The positive congestion costs in the AEP Control Zone were the result of negative load congestion payments offset by a bigger negative generation congestion credits. The Dominion Control Zone had the third highest congestion charges, $63.3 million, of any control zone in 2012. The positive congestion costs in the Dominion Control Zone were the result of relatively low positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for Dominion rather than offsetting the positive load congestion payments.

Table G-6 Congestion cost summary (By control zone): 2012

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$7.5	$3.5	$0.5	$4.4	$0.0	$0.5	($0.3)	($0.7)	$3.7
AEP	($81.4)	($189.5)	$23.3	$131.4	$5.9	$14.5	($18.6)	($27.2)	$104.2
AP	$5.1	($52.6)	$8.7	$66.4	$3.7	$9.1	($8.4)	($13.8)	$52.5
ATSI	($50.7)	($55.7)	$1.4	$6.5	$2.7	$6.0	$0.4	($3.0)	$3.5
BGE	$140.1	$103.7	$11.3	$47.7	$1.4	$1.4	($13.4)	($13.3)	$34.4
ComEd	($337.6)	($539.3)	$16.4	$218.2	$3.4	$17.7	($32.9)	($47.2)	$171.0
DAY	($12.6)	($15.2)	$7.4	$9.9	$0.6	$1.7	($3.9)	($4.9)	$5.0
DEOK	($12.3)	($14.4)	$5.9	$8.0	$0.6	$0.6	($4.9)	($5.0)	$3.0
DLCO	($5.1)	($14.8)	$0.6	$10.3	$0.1	$0.3	($0.3)	($0.6)	$9.7
DPL	$47.5	$16.2	$4.6	$35.9	($10.8)	$2.6	($7.7)	($21.1)	$14.8
Dominion	$228.2	$164.7	$15.8	$79.2	$3.2	($0.9)	($20.0)	($16.0)	$63.3
External	($42.9)	($26.8)	($0.2)	($16.4)	($9.0)	($3.0)	($33.7)	($39.7)	($56.0)
JCPL	$11.3	$1.5	$1.0	$10.7	$1.9	$1.7	$0.1	$0.3	$11.1
Met-Ed	$9.4	($0.6)	$1.5	$11.4	$0.0	$1.9	($2.6)	($4.5)	$7.0
PECO	$36.2	$20.4	$1.4	$17.2	$1.5	$5.0	($1.3)	($4.7)	$12.5
PENELEC	($2.5)	($35.0)	$2.4	$34.8	$0.9	$0.8	($2.0)	($1.9)	$32.9
PPL	$5.3	($5.6)	$1.1	$12.0	$2.0	$2.7	($0.6)	($1.3)	$10.7
PSEG	$45.6	$30.5	$17.6	$32.7	$1.4	$7.1	($22.6)	($28.3)	$4.4
Pepco	$143.9	$96.3	$11.1	$58.8	($6.6)	($1.2)	($12.6)	($18.0)	$40.8
RECO	$0.5	$0.0	$0.1	$0.6	$0.1	$0.0	($0.2)	($0.1)	$0.5
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0

Table G-7 Congestion cost summary (By control zone): 2011

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$45.4	$15.7	$0.7	$30.5	($0.4)	$0.2	($1.0)	($1.6)	$28.9
AEP	($377.8)	($606.7)	$23.0	$251.8	$9.4	$37.2	($28.9)	($56.7)	$195.1
AP	$6.9	($143.7)	($2.6)	$148.1	$5.7	$8.0	($1.8)	($4.1)	$143.9
ATSI	($73.8)	($78.5)	$1.6	$6.3	$2.1	$8.0	($3.3)	($9.2)	($2.9)
BGE	$233.4	$180.3	$8.0	$61.0	$2.8	$1.8	($11.5)	($10.5)	$50.5
ComEd	($1,064.7)	($1,323.5)	($4.2)	$254.6	$57.4	$46.2	($26.7)	($15.5)	$239.0
DAY	($61.3)	($70.1)	$1.3	$10.1	$3.4	$6.1	($4.4)	($7.1)	$3.0
DLCO	($43.2)	($67.9)	$0.0	$24.7	($3.0)	$0.7	($0.7)	($4.4)	$20.4
DPL	$71.3	$28.6	$1.3	$44.0	$0.5	$3.9	($1.8)	($5.2)	$38.8
Dominion	$537.7	$375.1	$23.1	$185.7	($4.8)	$4.5	($37.7)	($47.0)	$138.7
External	($56.3)	($42.5)	($6.5)	($20.3)	($10.4)	($19.1)	($23.8)	($15.1)	($35.4)
JCPL	$78.8	$35.4	$1.0	$44.4	$3.9	$1.3	($1.5)	$1.1	$45.5
Met-Ed	$46.0	$48.1	$0.5	($1.7)	$1.7	$0.8	($0.7)	$0.2	($1.5)
PECO	$178.0	$163.2	$0.9	$15.7	($0.9)	$5.2	($1.1)	($7.2)	$8.5
PENELEC	($45.9)	($108.1)	$0.7	$62.9	$4.2	$7.2	($1.2)	($4.2)	$58.7
PPL	$137.2	$142.1	$5.0	$0.0	$6.7	$2.9	($3.3)	$0.5	$0.5
PSEG	$191.8	$154.3	$7.6	$45.1	$1.3	$17.7	($33.9)	($50.4)	($5.3)
Pepco	$230.7	$156.5	$5.4	$79.6	($3.6)	($1.8)	($6.6)	($8.4)	$71.1
RECO	$2.3	($0.1)	$0.1	$2.6	$0.0	$1.0	($0.2)	($1.1)	$1.5
Total	$36.3	($1,141.8)	$66.9	$1,245.0	$75.9	$131.9	($190.0)	($246.0)	$999.0

Details of Regional and Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with seven control zones (the AP, ATSI, ComEd, AEP, DLCO, DEOK and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table G-8 through Table G-44 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2012 and 2011. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. The tables present the constraints in descending order of the absolute value of total congestion costs for each zone. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. In 2012, the RECO control zone only had one internal constraint, thus the RECO table shows the top 15 constraints and one local constraint.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table G-8 AECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($5.5)	($1.5)	($0.1)	($4.1)	$0.0	$0.1	$0.1	$0.0	($4.1)	5,328	1,446
2	West	Interface	500	$4.1	$1.8	$0.1	$2.3	($0.1)	$0.1	($0.0)	($0.2)	$2.1	1,682	260
3	Northwest	Other	BGE	($1.3)	($0.3)	($0.0)	($0.9)	($0.0)	$0.1	$0.0	($0.1)	($1.0)	1,168	804
4	Buxmont - Whitpain	Line	PECO	$1.4	$0.6	$0.1	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	638	6
5	East	Interface	500	$1.1	$0.4	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.7	418	10
6	AP South	Interface	500	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	($0.0)	$0.7	5,172	702
7	5004/5005 Interface	Interface	500	$0.5	$0.2	$0.0	$0.3	$0.1	($0.1)	($0.0)	$0.2	$0.5	382	256
8	Bedington - Black Oak	Interface	500	$0.7	$0.2	$0.0	$0.5	($0.0)	$0.0	($0.0)	($0.0)	$0.4	1,560	108
9	Clover	Transformer	Dominion	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.1)	($0.0)	$0.4	3,128	904
10	Rantoul - Rantoul Jct	Flowgate	MISO	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	4,072	630
11	Crete - St Johns Tap	Flowgate	MISO	$0.5	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	4,754	554
12	Higbee - Lewis	Line	AECO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.1)	($0.3)	($0.3)	4	52
13	Loudoun - Gainsville	Line	Dominion	$0.6	$0.3	$0.0	$0.3	$0.0	($0.0)	($0.0)	($0.0)	$0.3	322	38
14	Shieldalloy - Vineland	Line	AECO	$0.5	$0.1	$0.1	$0.5	($0.1)	($0.0)	($0.1)	($0.1)	$0.3	952	114
15	Palisades - Roosevelt	Flowgate	MISO	$0.4	$0.1	($0.0)	$0.3	$0.0	$0.0	$0.0	($0.0)	$0.3	1,710	418
24	Monroe - Shieldalloy	Line	AECO	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	494	0
27	Corson - Union	Line	AECO	$0.1	($0.0)	($0.0)	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	50	2
36	Absecon - Lewis	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.1	$0.2	($0.0)	($0.1)	$0.1	108	34
46	Sherman Avenue	Transformer	AECO	$0.1	$0.0	$0.0	$0.1	($0.0)	$0.0	($0.0)	($0.0)	$0.1	288	8
50	Corson - Sea Isle	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.1	$0.1	0	16

Table G-9 AECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$9.7	$3.7	$0.1	$6.1	$0.0	($0.0)	($0.0)	$0.0	$6.1	1,758	40
2	5004/5005 Interface	Interface	500	$7.4	$3.3	$0.0	$4.2	$0.2	($0.4)	($0.1)	$0.5	$4.6	1,810	940
3	Sherman Avenue	Transformer	AECO	$4.6	$0.3	$0.1	$4.3	($0.2)	($0.1)	($0.0)	($0.1)	$4.2	1,196	60
4	East	Interface	500	$3.8	$1.4	$0.0	$2.4	($0.0)	($0.0)	($0.0)	($0.0)	$2.3	1,046	44
5	Wylie Ridge	Transformer	AP	$2.8	$1.1	$0.0	$1.7	$0.1	($0.1)	($0.0)	$0.2	$2.0	3,836	760
6	Graceton - Raphael Road	Line	BGE	($2.0)	($0.6)	($0.0)	($1.4)	($0.0)	$0.1	$0.0	($0.1)	($1.5)	2,324	830
7	Crete - St Johns Tap	Flowgate	MISO	$1.6	$0.4	$0.0	$1.1	$0.1	($0.0)	($0.0)	$0.1	$1.2	6,756	2,240
8	Shieldalloy - Vineland	Line	AECO	$3.9	$0.8	$0.2	$3.2	($1.4)	$0.5	($0.3)	($2.2)	$1.0	1,496	468
9	AP South	Interface	500	$1.5	$0.6	$0.1	$0.9	($0.0)	($0.1)	($0.1)	$0.0	$1.0	8,240	2,026
10	Dickerson - Quince Orchard	Line	Pepco	$1.4	$0.7	$0.0	$0.7	$0.0	($0.1)	($0.0)	$0.1	$0.8	284	152
11	South Mahwah - Waldwick	Line	PSEG	$0.9	$0.3	$0.1	$0.7	$0.0	($0.0)	($0.1)	$0.0	$0.7	10,538	988
12	East Frankfort - Crete	Line	ComEd	$0.6	$0.2	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	3,092	658
13	Orchard - Orchard Tap	Line	AECO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	70	0
14	Plymouth Meeting - Whitpain	Line	PECO	$0.8	$0.4	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	412	144
15	Burnham - Munster	Flowgate	MISO	$0.6	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,304	0
37	Orchard	Transformer	AECO	$0.7	$0.4	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0
50	Corson	Transformer	AECO	$0.1	($0.0)	$0.0	$0.1	$0.4	$0.1	($0.0)	$0.2	$0.3	62	52
66	Carlls Corner - Sherman Ave	Line	AECO	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.2	($0.0)	($0.4)	($0.3)	188	88
76	Churchtown	Transformer	AECO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.0	($0.1)	($0.1)	0	66
82	Carnegie - Tidd	Line	AECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,704	0

BGE Control Zone

Table G-10 BGE Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	$39.9	$27.8	$2.7	$14.8	$0.3	$0.3	($2.0)	($2.0)	$12.8	5,328	1,446
2	AP South	Interface	500	$21.3	$17.8	$1.6	$5.1	$0.8	($0.5)	($2.4)	($1.1)	$4.0	5,172	702
3	West	Interface	500	$14.1	$10.7	$0.5	$3.9	$0.1	($0.1)	($0.5)	($0.3)	$3.6	1,682	260
4	Bedington - Black Oak	Interface	500	$9.3	$7.8	$0.8	$2.3	$0.1	($0.2)	($0.3)	$0.0	$2.3	1,560	108
5	Loudoun - Gainsville	Line	Dominion	$4.3	$3.6	$0.2	$0.9	$0.0	($0.0)	($0.1)	($0.1)	$0.9	322	38
6	Clover	Transformer	Dominion	$5.0	$4.3	$0.5	$1.2	$0.3	($0.1)	($0.8)	($0.4)	$0.8	3,128	904
7	Green Street - Westport	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	278	0
8	High Ridge - Howard	Line	BGE	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	104	0
9	Howard - Pumphrey	Line	Pepco	$1.4	$0.8	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	298	0
10	Hazelwood - Windy Edge	Line	BGE	$0.9	$0.2	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	80	0
11	Northwest	Other	BGE	$9.8	$6.1	$0.6	$4.4	($1.5)	$1.2	($1.1)	($3.7)	$0.7	1,168	804
12	Bcpep	Interface	Pepco	$2.7	$2.2	$0.2	$0.7	$0.0	($0.0)	($0.2)	($0.2)	$0.6	178	12
13	Rantoul - Rantoul Jct	Flowgate	MISO	$2.4	$2.1	$0.2	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	4,072	630
14	Crete - St Johns Tap	Flowgate	MISO	$2.5	$2.1	$0.1	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	4,754	554
15	Stephenson - Stonewall	Line	AP	$1.6	$1.3	$0.1	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.4	538	42
20	Erdman - Monument St.	Line	BGE	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	34	0
23	Conastone - Otter	Line	BGE	$2.3	$2.1	$0.3	$0.5	$0.1	$0.1	($0.3)	($0.3)	$0.3	490	350
24	Brandon Shores - Riverside	Line	BGE	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	208	6
29	Conastone - Northwest	Line	BGE	$0.5	$0.3	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	80	4
34	Graceton	Transformer	BGE	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	68	162

Table G-11 BGE Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$29.1	$21.1	$0.5	$8.5	$0.0	($0.1)	($0.0)	$0.1	$8.6	1,758	40
2	AP South	Interface	500	$58.6	$53.5	$1.7	$6.9	$1.4	($0.5)	($1.7)	$0.3	$7.1	8,240	2,026
3	Dickerson - Quince Orchard	Line	Pepco	$15.2	$11.0	$0.1	$4.3	$0.6	$0.4	($0.4)	($0.1)	$4.2	284	152
4	Wagner	Transformer	BGE	$4.2	$0.8	$0.1	$3.5	($0.1)	($0.6)	($0.3)	$0.2	$3.7	402	52
5	Graceton - Raphael Road	Line	BGE	$14.6	$11.0	$0.6	$4.2	($0.1)	$0.4	($0.7)	($1.2)	$3.1	2,324	830
6	Pumphrey	Transformer	Pepco	$4.9	$2.1	$0.2	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	486	0
7	5004/5005 Interface	Interface	500	$10.9	$8.4	$0.1	$2.6	$0.1	($0.2)	($0.1)	$0.2	$2.8	1,810	940
8	Wylie Ridge	Transformer	AP	$12.0	$10.3	$0.3	$2.0	$0.3	($0.1)	($0.2)	$0.2	$2.2	3,836	760
9	Conastone - Graceton	Line	BGE	$5.3	$3.6	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	236	0
10	Crete - St Johns Tap	Flowgate	MISO	$7.9	$6.7	$0.2	$1.4	$0.3	$0.1	($0.2)	$0.0	$1.5	6,756	2,240
11	High Ridge - Howard	Line	BGE	$3.2	$1.0	$0.2	$2.3	($0.7)	($0.2)	($0.4)	($0.9)	$1.4	204	92
12	Glenarm - Windy Edge	Line	BGE	$5.3	$3.6	$0.3	$2.0	($0.0)	$0.3	($0.2)	($0.6)	$1.4	1,366	316
13	Brandon Shores - Riverside	Line	BGE	$0.9	($0.4)	$0.1	$1.3	($0.1)	($0.1)	($0.1)	($0.1)	$1.2	276	18
14	Bedington - Black Oak	Interface	500	$9.0	$7.9	$0.1	$1.2	($0.0)	($0.0)	($0.0)	($0.0)	$1.2	1,358	14
15	East	Interface	500	($4.5)	($3.8)	($0.2)	($0.9)	($0.0)	$0.1	$0.0	($0.1)	($1.0)	1,046	44
16	Erdman - Monument St.	Line	BGE	$1.0	$0.2	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	14	0
17	Riverside	Other	BGE	$2.8	$0.0	$0.1	$2.9	($0.1)	$2.8	($0.9)	($3.7)	($0.8)	792	262
19	Howard - Pumphrey	Line	BGE	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.9)	($0.8)	($0.6)	($0.6)	0	120
27	Northwest	Other	BGE	$0.7	$0.5	$0.0	$0.3	($0.1)	$0.3	($0.2)	($0.6)	($0.4)	90	206
29	Chesaco Park - Gray Manor	Line	BGE	$0.3	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	104	0

DPL Control Zone

Table G-12 DPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($10.7)	($4.3)	($0.8)	($7.2)	($0.2)	($0.6)	$0.6	$1.0	($6.2)	5,328	1,446
2	West	Interface	500	$7.4	$3.6	$0.3	$4.0	$0.1	$0.2	($0.2)	($0.3)	$3.7	1,682	260
3	Mardela - Vienna	Line	DPL	$3.6	$1.3	$0.4	$2.7	($4.2)	($0.1)	($2.1)	($6.2)	($3.4)	412	252
4	Lumspond - Reybold	Line	DPL	$2.3	$0.3	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	504	0
5	Longwood - Wye Mills	Line	DPL	$3.5	$0.9	$0.2	$2.7	($0.5)	$0.0	($0.3)	($0.8)	$1.9	1,308	90
6	Kenney - Stockton	Line	DPL	$11.7	$3.5	$1.1	$9.3	($6.3)	$1.6	($3.2)	($11.0)	($1.7)	1,368	982
7	Cedar Creek - Red Lion	Line	DPL	$2.0	$0.4	$0.2	$1.8	($0.1)	$0.0	($0.1)	($0.2)	$1.6	450	26
8	East	Interface	500	$2.1	$0.7	$0.0	$1.5	($0.0)	$0.1	($0.0)	($0.1)	$1.4	418	10
9	Church - Townsend	Line	DPL	$2.2	$0.3	$0.3	$2.2	($0.3)	$0.4	($0.4)	($1.0)	$1.1	672	76
10	Buxmont - Whitpain	Line	PECO	$2.1	$1.2	$0.1	$1.0	($0.0)	$0.0	($0.0)	($0.0)	$1.0	638	6
11	AP South	Interface	500	$2.1	$0.9	$0.2	$1.4	$0.1	$0.2	($0.3)	($0.4)	$1.0	5,172	702
12	Chichester - Eddystone	Line	PECO	($0.4)	($0.3)	($0.1)	($0.2)	($0.0)	($1.0)	$0.2	$1.2	$1.0	102	90
13	Easton - Trappe	Line	DPL	$1.0	$0.3	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	548	0
14	Bedington - Black Oak	Interface	500	$1.4	$0.7	$0.2	$0.8	$0.0	$0.0	($0.1)	($0.1)	$0.7	1,560	108
15	New Church - Piney Grove	Line	DPL	$0.3	$0.0	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,114	0
16	North Salisbury - Rockawalkin	Line	DPL	$0.7	$0.3	$0.0	$0.5	($0.4)	$0.3	($0.3)	($1.0)	($0.5)	124	32
19	Talbot - Tanyard	Line	DPL	$2.1	$0.7	($0.0)	$1.4	($0.6)	$0.2	($0.0)	($0.8)	$0.5	346	132
20	Preston - Tanyard	Line	DPL	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	716	0
22	Easton - Easton Tap	Line	DPL	$0.8	$0.2	$0.0	$0.6	($0.1)	$0.1	($0.0)	($0.2)	$0.5	618	0
23	Mount Hermon - North	Line	DPL	$0.5	$0.1	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	62	6

Table G-13 DPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$14.0	$5.0	$0.1	$9.1	$0.3	$0.8	($0.3)	($0.8)	$8.3	1,810	940
2	West	Interface	500	$16.2	$8.8	$0.2	$7.6	$0.0	$0.0	($0.0)	$0.0	$7.6	1,758	40
3	Wylie Ridge	Transformer	AP	$5.7	$1.6	$0.1	$4.1	$0.1	$0.2	($0.0)	($0.1)	$4.0	3,836	760
4	East	Interface	500	$7.0	$3.1	($0.0)	$3.8	($0.0)	$0.1	($0.0)	($0.1)	$3.8	1,046	44
5	AP South	Interface	500	$4.1	$1.5	$0.2	$2.9	$0.0	$0.3	($0.3)	($0.6)	$2.3	8,240	2,026
6	Crete - St Johns Tap	Flowgate	MISO	$3.0	$0.8	$0.0	$2.3	$0.1	$0.3	($0.0)	($0.2)	$2.0	6,756	2,240
7	Graceton - Raphael Road	Line	BGE	($3.9)	($1.4)	($0.3)	($2.8)	($0.1)	($0.6)	$0.2	$0.8	($2.0)	2,324	830
8	New Church - Piney Grove	Line	DPL	$2.1	$0.4	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	980	0
9	Plymouth Meeting - Whitpain	Line	PECO	$2.3	$1.0	$0.0	$1.3	$0.1	$0.1	($0.1)	($0.0)	$1.3	412	144
10	Longwood - Wye Mills	Line	DPL	$1.5	$0.4	$0.1	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.2	1,776	6
11	Burnham - Munster	Flowgate	MISO	$1.1	$0.4	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	2,304	0
12	East Frankfort - Crete	Line	ComEd	$1.1	$0.3	$0.0	$0.8	$0.0	$0.1	$0.0	($0.1)	$0.7	3,092	658
13	Glenarm - Windy Edge	Line	BGE	($1.1)	($0.4)	($0.0)	($0.8)	($0.0)	($0.1)	$0.0	$0.1	($0.7)	1,366	316
14	Bedington - Black Oak	Interface	500	$0.9	$0.2	$0.0	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.6	1,358	14
15	Dickerson - Quince Orchard	Line	Pepco	$2.5	$1.6	$0.0	$1.0	$0.1	$0.4	($0.0)	($0.4)	$0.6	284	152
22	Hallwood - Oak Hall	Line	DPL	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	362	0
24	Mardela - Vienna	Line	DPL	$0.4	$0.1	$0.0	$0.4	($0.2)	$0.4	($0.1)	($0.8)	($0.4)	310	52
28	Easton - Trappe	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	248	0
46	Bellehaven - Tasley	Line	DPL	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,222	0
52	Oak Hall	Transformer	DPL	$0.2	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	10	0

JCPL Control Zone

Table G-14 JCPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$8.4	$4.2	$0.1	$4.3	($0.0)	$0.1	($0.1)	($0.2)	$4.1	1,682	260
2	Graceton - Raphael Road	Line	BGE	($11.4)	($7.7)	($0.4)	($4.0)	$0.4	$0.1	$0.3	$0.5	($3.5)	5,328	1,446
3	East	Interface	500	$1.9	$0.9	$0.0	$1.1	($0.0)	($0.0)	($0.0)	($0.0)	$1.1	418	10
4	Red Oak - Sayreville	Line	JCPL	($0.1)	($1.2)	($0.2)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,888	0
5	Bridgewater - Middlesex	Line	PSEG	$1.6	$0.7	$0.2	$1.1	$0.0	$0.3	$0.1	($0.2)	$0.9	1,694	62
6	5004/5005 Interface	Interface	500	$1.3	$0.7	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.0	$0.7	382	256
7	Northwest	Other	BGE	($2.7)	($2.1)	($0.0)	($0.7)	$0.0	$0.1	$0.1	$0.0	($0.6)	1,168	804
8	Harwood - Susquehanna	Line	PPL	$0.8	$0.3	$0.1	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	772	40
9	Roseland - Whippany	Line	PSEG	($0.9)	($0.4)	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,794	0
10	Loudoun - Gainsville	Line	Dominion	$1.2	$0.7	$0.0	$0.5	$0.0	$0.0	($0.0)	$0.0	$0.5	322	38
11	Clover	Transformer	Dominion	$1.1	$0.7	$0.0	$0.5	$0.1	$0.0	($0.1)	($0.0)	$0.5	3,128	904
12	Franklin - Vernon	Line	JCPL	($0.0)	$0.0	$0.5	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,420	0
13	Kittatiny - Newton	Line	JCPL	$0.4	($0.0)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	56	0
14	Crete - St Johns Tap	Flowgate	MISO	$1.0	$0.5	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.4	4,754	554
15	Rantoul - Rantoul Jct	Flowgate	MISO	$1.0	$0.6	$0.0	$0.4	$0.0	($0.0)	($0.0)	($0.0)	$0.4	4,072	630
25	Newton - Illiff	Line	JCPL	$0.2	($0.0)	($0.0)	$0.2	($0.0)	$0.0	$0.0	$0.0	$0.2	570	18
47	Gilbert - Glen Gardner	Line	JCPL	$0.2	$0.0	$0.0	$0.2	$0.1	$0.2	($0.0)	($0.1)	$0.1	42	36
60	Franklin - West Wharton	Line	JCPL	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	964	0
75	Atlantic - Larrabee	Line	JCPL	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	214	0
201	Montville - Roseland	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0

Table G-15 JCPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$19.0	$8.6	$0.1	$10.5	$0.9	$0.2	($0.1)	$0.6	$11.0	1,810	940
2	West	Interface	500	$19.8	$11.4	$0.1	$8.6	($0.0)	($0.0)	($0.0)	($0.0)	$8.5	1,758	40
3	Red Oak - Sayreville	Line	JCPL	($1.3)	($5.3)	($0.1)	$3.9	$0.0	$0.1	$0.0	($0.1)	$3.8	3,504	22
4	South Mahwah - Waldwick	Line	PSEG	$6.7	$3.0	$0.3	$4.1	($0.1)	($0.0)	($0.3)	($0.4)	$3.7	10,538	988
5	Wylie Ridge	Transformer	AP	$6.5	$3.0	$0.0	$3.5	$0.1	$0.1	($0.0)	($0.0)	$3.5	3,836	760
6	East	Interface	500	$6.7	$3.7	$0.0	$3.0	($0.1)	$0.0	($0.0)	($0.1)	$2.9	1,046	44
7	Bridgewater - Middlesex	Line	PSEG	$4.6	$1.8	$0.2	$3.0	($0.2)	$0.2	($0.5)	($0.9)	$2.1	1,108	126
8	Cedar Grove - Roseland	Line	PSEG	($3.1)	($1.2)	($0.1)	($2.1)	$0.0	$0.0	$0.0	$0.0	($2.0)	1,842	78
9	Crete - St Johns Tap	Flowgate	MISO	$3.6	$1.8	$0.0	$1.8	$0.1	$0.1	($0.0)	($0.0)	$1.8	6,756	2,240
10	Dickerson - Quince Orchard	Line	Pepco	$2.6	$1.6	$0.0	$1.0	$0.4	$0.1	($0.0)	$0.3	$1.3	284	152
11	Graceton - Raphael Road	Line	BGE	($4.1)	($2.7)	($0.1)	($1.5)	$0.4	$0.1	$0.1	$0.4	($1.2)	2,324	830
12	East Windsor - Smithburg	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.9	($0.0)	$0.0	$0.9	$0.9	0	18
13	Susquehanna	Transformer	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	240	0
14	East Frankfort - Crete	Line	ComEd	$1.4	$0.8	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	3,092	658
15	Atlantic - Larrabee	Line	JCPL	$0.4	($0.2)	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.6	170	2
42	Flanders - W. Wharton	Line	JCPL	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	550	0
49	Kilmer - Sayreville	Line	JCPL	$0.3	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	186	0
63	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	28
165	Lakewood - Larrabee	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
178	Kittatiny - Newton	Line	JCPL	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Met-Ed Control Zone

Table G-16 Met-Ed Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hunterstown	Transformer	Met-Ed	$3.8	$0.4	$0.1	$3.6	($0.1)	$0.0	($0.0)	($0.1)	$3.4	1,396	136
2	Graceton - Raphael Road	Line	BGE	($10.5)	($13.5)	($0.3)	$2.8	$0.2	$0.2	$0.2	$0.2	$3.0	5,328	1,446
3	West	Interface	500	$6.1	$7.9	$0.8	($1.0)	$0.0	$0.1	($0.4)	($0.5)	($1.5)	1,682	260
4	Northwest	Other	BGE	($2.5)	($4.0)	($0.1)	$1.4	$0.2	$0.3	$0.1	$0.1	$1.5	1,168	804
5	Conemaugh - Hunterstown	Line	500	$0.3	$0.6	$0.1	($0.2)	($0.0)	$0.0	($1.1)	($1.1)	($1.3)	76	234
6	Gardners - Texas East	Line	Met-Ed	$0.5	($0.5)	$0.0	$1.0	($0.1)	$0.1	($0.0)	($0.2)	$0.8	1,186	74
7	Middletown Jctn. - Middletown Jctn.	Other	Met-Ed	$0.7	($0.0)	$0.0	$0.8	($0.0)	$0.0	$0.0	($0.1)	$0.7	94	14
8	Carlisle Pike - Gardners	Line	PENELEC	$0.5	$0.1	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	482	0
9	Dillsburg - Gardners	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.0)	($0.4)	($0.4)	0	78
10	Three Mile Island	Transformer	Met-Ed	$0.9	$1.1	$0.0	($0.2)	($0.0)	$0.0	($0.2)	($0.2)	($0.4)	324	110
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	1,040	0
12	Smith Jct - Smith St.	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.3)	($0.3)	($0.3)	6	14
13	Graceton - Safe Harbor	Line	BGE	($0.7)	($0.9)	($0.1)	$0.1	$0.1	$0.1	$0.2	$0.2	$0.3	438	194
14	Buxmont - Whitpain	Line	PECO	($2.1)	($2.1)	($0.3)	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	638	6
15	Jackson - North Hanover	Line	Met-Ed	$0.3	($0.0)	$0.0	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	108	42
16	Middletown Jct	Transformer	Met-Ed	$0.4	($0.0)	$0.1	$0.5	$0.0	$0.0	($0.2)	($0.2)	$0.3	268	32
17	Jackson - Three Mile Island	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	90	0
22	Jackson - TMI	Line	Met-Ed	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($0.1)	($0.2)	($0.2)	0	54
26	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	68	0
28	Ironwood - South Lebanon	Line	Met-Ed	$0.0	($0.2)	($0.0)	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	134	0

Table G-17 Met-Ed Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$10.9	$15.5	$0.1	($4.6)	$0.0	$0.0	($0.0)	($0.0)	($4.6)	1,758	40
2	Cly - Collins	Line	Met-Ed	$1.9	($1.3)	$0.1	$3.3	($0.5)	$0.4	($0.0)	($0.9)	$2.3	710	324
3	Wylie Ridge	Transformer	AP	$4.4	$6.3	$0.1	($1.8)	$0.1	($0.0)	($0.0)	$0.1	($1.7)	3,836	760
4	Hunterstown	Transformer	Met-Ed	$1.6	$0.0	$0.0	$1.5	$0.0	$0.0	($0.0)	$0.0	$1.5	164	18
5	Crete - St Johns Tap	Flowgate	MISO	$2.4	$3.4	($0.0)	($1.0)	$0.1	($0.0)	($0.0)	$0.1	($0.9)	6,756	2,240
6	Graceton - Raphael Road	Line	BGE	($3.3)	($4.6)	($0.2)	$1.1	($0.1)	$0.2	$0.1	($0.2)	$0.9	2,324	830
7	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$0.4	($0.7)	$0.0	$1.1	($0.1)	$0.1	($0.1)	($0.4)	$0.7	62	30
8	East	Interface	500	$0.4	($0.2)	($0.1)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,046	44
9	Carlisle Pike - Roxbury	Line	PENELEC	$0.6	$0.1	$0.0	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.5	268	8
10	Dickerson - Quince Orchard	Line	Pepco	$1.3	$1.9	$0.0	($0.5)	$0.2	$0.1	($0.0)	$0.1	($0.5)	284	152
11	East Frankfort - Crete	Line	ComEd	$0.9	$1.3	$0.0	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	3,092	658
12	Burnham - Munster	Flowgate	MISO	$1.0	$1.4	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
13	Conastone - Graceton	Line	BGE	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	236	0
14	Glenarm - Windy Edge	Line	BGE	($1.1)	($1.4)	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.3	1,366	316
15	Susquehanna	Transformer	PPL	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	240	0
20	Glendon - Hosensack	Line	Met-Ed	$0.1	($0.1)	($0.0)	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	162	2
28	Hunterstown - Lincoln	Line	Met-Ed	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	220	16
30	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	74	0
37	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
69	Manor - Safe Harbor	Line	Met-Ed	($0.1)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	($0.0)	14	6

PECO Control Zone

Table G-18 PECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($28.8)	($42.0)	($0.3)	$12.9	$0.3	$0.3	$0.2	$0.2	$13.1	5,328	1,446
2	West	Interface	500	$18.8	$25.4	$0.2	($6.4)	($0.1)	$0.3	($0.1)	($0.5)	($6.9)	1,682	260
3	Northwest	Other	BGE	($6.5)	($10.5)	($0.1)	$3.9	$0.3	$0.3	$0.1	$0.1	$4.0	1,168	804
4	Plymouth Meeting - Whitpain	Line	PECO	$5.8	$2.1	$0.1	$3.8	($0.1)	$0.8	($0.0)	($0.9)	$2.9	230	88
5	AP South	Interface	500	$4.4	$6.9	$0.1	($2.3)	($0.0)	$0.2	($0.2)	($0.4)	($2.7)	5,172	702
6	Buxmont - Whitpain	Line	PECO	$8.6	$6.5	$0.1	$2.2	($0.0)	$0.0	($0.0)	($0.0)	$2.2	638	6
7	Tuna - Waneeta	Line	PECO	$1.8	$0.5	$0.0	$1.4	($0.1)	$0.0	($0.1)	($0.2)	$1.2	282	62
8	Crete - St Johns Tap	Flowgate	MISO	$2.3	$3.5	$0.0	($1.1)	$0.0	($0.0)	($0.0)	($0.0)	($1.1)	4,754	554
9	Three Mile Island	Transformer	Met-Ed	($1.5)	($2.7)	($0.0)	$1.1	($0.0)	$0.1	$0.1	($0.0)	$1.1	324	110
10	5004/5005 Interface	Interface	500	$2.4	$3.3	$0.0	($0.9)	$0.0	$0.1	($0.1)	($0.2)	($1.0)	382	256
11	Bedington - Black Oak	Interface	500	$3.2	$4.3	$0.1	($0.9)	$0.0	$0.1	($0.1)	($0.1)	($1.0)	1,560	108
12	East	Interface	500	$4.5	$3.5	$0.0	$1.0	($0.0)	$0.1	($0.0)	($0.1)	$0.9	418	10
13	Emilie	Transformer	PECO	($0.5)	($1.9)	$0.0	$1.4	$0.0	$0.4	($0.1)	($0.5)	$0.9	2,064	388
14	Conastone - Otter	Line	BGE	($1.6)	($2.6)	($0.0)	$1.0	$0.0	$0.1	$0.0	($0.1)	$0.9	490	350
15	Central	Interface	500	$1.8	$2.6	$0.0	($0.8)	$0.0	$0.0	$0.0	($0.0)	($0.8)	428	4
16	Bala - Plymouth Meeting	Line	PECO	$1.4	$0.6	($0.0)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	38	0
19	Cromby	Transformer	PECO	$0.6	($0.0)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	220	0
21	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	$0.0	$0.5	$1.2	$0.0	($0.7)	($0.6)	36	20
22	Chichester - Eddystone	Line	PECO	$0.7	$0.1	$0.1	$0.7	$0.1	$0.1	($0.1)	($0.1)	$0.6	102	2
30	Peachbottom	Transformer	PECO	$0.2	($0.2)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	40	10

Table G-19 PECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$38.1	$45.9	$0.1	($7.6)	($0.0)	($0.0)	($0.0)	$0.0	($7.6)	1,758	40
2	Plymouth Meeting - Whitpain	Line	PECO	$11.1	$3.2	$0.0	$7.9	($0.3)	($0.0)	($0.1)	($0.4)	$7.6	412	144
3	East	Interface	500	$14.2	$8.9	$0.1	$5.4	($0.1)	$0.1	($0.0)	($0.2)	$5.2	1,046	44
4	Cromby	Transformer	PECO	$6.4	$0.6	$0.0	$5.8	($0.7)	$0.4	($0.0)	($1.1)	$4.7	756	304
5	Bryn Mawr - Plymouth Meeting	Line	PECO	$6.5	$2.0	$0.0	$4.4	($0.1)	($0.1)	$0.0	$0.0	$4.5	568	8
6	Graceton - Raphael Road	Line	BGE	($9.8)	($13.9)	($0.1)	$3.9	$0.5	$0.1	$0.1	$0.6	$4.5	2,324	830
7	AP South	Interface	500	$7.6	$11.8	$0.1	($4.0)	($0.2)	$0.1	($0.1)	($0.4)	($4.4)	8,240	2,026
8	5004/5005 Interface	Interface	500	$36.1	$38.8	$0.2	($2.5)	($0.6)	$1.0	($0.1)	($1.8)	($4.3)	1,810	940
9	Wylie Ridge	Transformer	AP	$14.0	$16.8	$0.1	($2.7)	($0.1)	$0.0	($0.1)	($0.1)	($2.8)	3,836	760
10	Bradford - Planebrook	Line	PECO	$2.4	($0.1)	$0.0	$2.5	$0.1	$0.3	$0.0	($0.2)	$2.3	242	86
11	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.0	$0.2	($0.0)	($0.2)	($2.1)	6,756	2,240
12	Dickerson - Quince Orchard	Line	Pepco	$5.9	$7.5	$0.0	($1.5)	$0.2	$0.5	($0.0)	($0.3)	($1.8)	284	152
13	Bala - Plymouth Meeting	Line	PECO	$2.6	$0.8	($0.0)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	152	0
14	Conastone - Graceton	Line	BGE	($0.6)	($2.1)	($0.0)	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	236	0
15	Chichester	Transformer	PECO	$1.5	$0.1	$0.0	$1.5	($0.0)	$0.0	($0.0)	($0.1)	$1.4	118	8
16	Limerick	Transformer	PECO	$2.1	$0.7	($0.0)	$1.4	($0.0)	$0.0	($0.0)	($0.0)	$1.4	60	10
26	Eddystone - Saville	Line	PECO	$0.6	($0.0)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.0)	$0.6	136	32
27	Emilie	Transformer	PECO	($0.2)	($0.8)	($0.0)	$0.7	$0.1	$0.3	$0.0	($0.2)	$0.5	648	306
32	Eddington - Holmesburg	Line	PECO	($0.0)	($0.4)	($0.0)	$0.4	($0.1)	$0.7	($0.0)	($0.8)	($0.4)	482	356
36	Blue Grass - Byberry	Line	PECO	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	116	0

PENELEC Control Zone

Table G-20 PENELEC Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	($5.6)	($12.9)	($0.5)	$6.8	$0.1	$0.7	$0.3	($0.3)	$6.5	1,682	260
2	AP South	Interface	500	($11.0)	($14.9)	($0.2)	$3.7	$0.9	$0.0	$0.3	$1.2	$4.9	5,172	702
3	Graceton - Raphael Road	Line	BGE	($9.5)	($11.7)	($0.1)	$2.1	$0.4	($0.1)	$0.0	$0.6	$2.8	5,328	1,446
4	Hooversville	Transformer	PENELEC	$6.7	$4.0	($0.0)	$2.7	$0.0	$0.0	($0.0)	($0.0)	$2.7	266	20
5	Hunterstown	Transformer	Met-Ed	($0.9)	($2.7)	($0.0)	$1.7	$0.0	($0.4)	$0.0	$0.4	$2.1	1,396	136
6	Johnstown	Transformer	PENELEC	$4.1	$2.6	$0.2	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	32	0
7	5004/5005 Interface	Interface	500	($0.9)	($2.5)	($0.1)	$1.4	$0.5	$0.7	$0.3	$0.1	$1.6	382	256
8	Bedington - Black Oak	Interface	500	($4.1)	($5.6)	$0.0	$1.4	$0.0	$0.1	$0.0	($0.0)	$1.4	1,560	108
9	East Sayre - North Waverly	Line	PENELEC	$1.9	$1.1	$0.4	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	2,840	0
10	Seward	Transformer	PENELEC	$1.8	$0.9	$0.1	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	156	0
11	Keystone - Shelocta	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	($1.6)	($1.2)	($0.4)	($0.9)	($0.9)	8	10
12	Northwest	Other	BGE	($2.1)	($2.0)	$0.1	($0.1)	$0.3	($0.6)	($0.0)	$0.9	$0.9	1,168	804
13	Butler - Karns City	Line	AP	$2.9	$2.1	$0.1	$0.9	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	686	18
14	Garretts Run - Kiski Valley	Line	AP	$3.6	$2.7	$0.1	$1.0	($0.1)	$0.0	($0.1)	($0.2)	$0.8	840	206
15	Crete - St Johns Tap	Flowgate	MISO	$2.3	$2.8	$0.1	($0.3)	($0.1)	$0.2	($0.0)	($0.3)	($0.6)	4,754	554
16	Altoona - Bear Rock	Line	PENELEC	($0.3)	($0.8)	($0.0)	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	56	6
21	Laurel Lake - Tiffany	Line	PENELEC	$0.5	$0.1	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	892	0
23	Blairsville East	Transformer	PENELEC	($1.7)	($2.0)	($0.1)	$0.1	$0.2	$0.0	$0.1	$0.2	$0.3	390	20
24	Garrett - Garrett Tap	Line	PENELEC	$1.7	$1.4	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	164	16
27	East Towanda - Hillside	Line	PENELEC	$0.3	$0.1	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	616	0

Table G-21 PENELEC Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	($14.9)	($39.4)	($1.7)	$22.8	$1.7	$3.0	$2.5	$1.3	$24.1	1,810	940
2	AP South	Interface	500	($38.8)	($54.6)	($0.4)	$15.5	$2.7	$0.7	$0.9	$2.9	$18.4	8,240	2,026
3	West	Interface	500	($11.1)	($26.8)	($1.4)	$14.3	$0.0	$0.1	$0.1	$0.0	$14.3	1,758	40
4	Wylie Ridge	Transformer	AP	$8.1	$20.0	$0.8	($11.1)	($0.6)	($0.4)	($0.4)	($0.6)	($11.7)	3,836	760
5	Crete - St Johns Tap	Flowgate	MISO	$7.4	$10.0	$0.1	($2.5)	($0.3)	$0.2	($0.1)	($0.6)	($3.1)	6,756	2,240
6	Altoona - Bear Rock	Line	PENELEC	($2.8)	($5.5)	($0.1)	$2.6	$0.7	$0.6	$0.2	$0.2	$2.9	380	154
7	Johnstown - Seward	Line	PENELEC	$2.0	($0.6)	$0.0	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	102	0
8	Bedington - Black Oak	Interface	500	($5.1)	($7.5)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1,358	14
9	Butler - Karns City	Line	AP	$5.5	$3.9	$0.3	$2.0	($0.2)	$0.0	($0.1)	($0.3)	$1.7	782	116
10	Susquehanna	Transformer	PPL	$0.5	($1.3)	($0.1)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	240	0
11	Yukon	Transformer	AP	$0.9	($0.9)	($0.0)	$1.8	($0.0)	$0.2	$0.0	($0.2)	$1.6	750	180
12	East	Interface	500	($2.4)	($4.2)	($0.3)	$1.5	$0.0	$0.1	$0.1	$0.0	$1.5	1,046	44
13	Graceton - Raphael Road	Line	BGE	($3.1)	($3.8)	($0.1)	$0.6	$0.2	$0.1	$0.1	$0.2	$0.8	2,324	830
14	East Frankfort - Crete	Line	ComEd	$2.9	$3.6	$0.1	($0.6)	$0.0	$0.1	($0.1)	($0.2)	($0.8)	3,092	658
15	AEP - DOM	Interface	500	($2.4)	($3.1)	$0.0	$0.7	$0.1	$0.0	$0.0	$0.0	$0.8	3,578	370
17	Laurel Lake - Tiffany	Line	PENELEC	$0.7	$0.1	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	154	0
23	Seward	Transformer	PENELEC	$0.4	$0.2	$0.0	$0.2	($0.2)	$0.5	($0.0)	($0.8)	($0.5)	42	44
26	East Towanda - S.Troy	Line	PENELEC	$0.2	$0.1	$0.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	1,450	0
28	Hooversville - Scalp Level	Line	PENELEC	$2.9	$2.1	$0.1	$0.8	($0.2)	$0.1	($0.1)	($0.4)	$0.5	434	110
35	Handsome Lake - Wayne	Line	PENELEC	$0.2	($0.2)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	48	0

Pepco Control Zone

Table G-22 Pepco Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	$30.7	$20.0	$1.6	$12.4	($0.4)	$0.9	($1.0)	($2.4)	$10.0	5,328	1,446
2	AP South	Interface	500	$28.4	$19.3	$1.4	$10.5	($0.8)	$0.8	($1.9)	($3.6)	$6.9	5,172	702
3	Bedington - Black Oak	Interface	500	$12.3	$8.7	$0.6	$4.2	$0.0	$0.3	($0.2)	($0.5)	$3.8	1,560	108
4	West	Interface	500	$9.1	$6.5	$0.3	$2.9	($0.1)	($0.0)	($0.1)	($0.2)	$2.6	1,682	260
5	Buzzard - Ritchie	Line	Pepco	$4.7	$2.0	$0.4	$3.1	($3.4)	($5.1)	($2.2)	($0.5)	$2.6	1,008	294
6	Potomac River	Transformer	Pepco	$3.1	$1.4	$0.2	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	1,074	0
7	Loudoun - Gainsville	Line	Dominion	$5.8	$4.2	$0.2	$1.8	($0.1)	$0.0	($0.1)	($0.2)	$1.6	322	38
8	Northwest	Other	BGE	$8.3	$5.7	$0.4	$3.0	($0.4)	$0.6	($0.6)	($1.6)	$1.4	1,168	804
9	Rantoul - Rantoul Jct	Flowgate	MISO	$2.6	$1.9	$0.7	$1.4	($0.0)	$0.0	($0.0)	($0.1)	$1.3	4,072	630
10	AEP - DOM	Interface	500	$3.5	$2.6	$0.2	$1.1	($0.1)	$0.0	($0.1)	($0.1)	$0.9	4,190	122
11	Crete - St Johns Tap	Flowgate	MISO	$2.6	$1.8	$0.2	$1.0	($0.0)	$0.0	($0.0)	($0.1)	$0.9	4,754	554
12	Clover	Transformer	Dominion	$6.3	$4.7	$0.5	$2.1	($0.3)	$0.3	($0.7)	($1.3)	$0.8	3,128	904
13	Potomac	Transformer	Pepco	$1.4	$1.1	$0.3	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	1,232	20
14	Burches Hill - Palmers Corner	Line	Pepco	$1.0	$0.4	$0.1	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	742	0
15	Conastone - Otter	Line	BGE	$2.3	$1.4	$0.2	$1.0	($0.1)	($0.1)	($0.4)	($0.4)	$0.6	490	350
18	Bcpep	Interface	Pepco	$2.9	$1.8	$0.1	$1.2	($0.0)	$0.5	($0.1)	($0.7)	$0.5	178	12
22	Oak Grove - Ritchie	Line	Pepco	$0.6	$0.2	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	382	2
24	Dickerson - Quince Orchard	Line	Pepco	$0.3	$0.1	$0.0	$0.2	($0.2)	$0.3	($0.1)	($0.6)	($0.4)	28	34
26	Burtonsville - Sandy Springs	Line	Pepco	($0.3)	($0.2)	($0.0)	($0.1)	$0.3	$0.1	$0.3	$0.5	$0.4	102	0
36	Buzzard Point	Transformer	Pepco	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	60	0

Table G-23 Pepco Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$79.8	$58.9	$1.4	$22.2	($2.2)	($1.5)	($1.3)	($2.0)	$20.1	8,240	2,026
2	Dickerson - Quince Orchard	Line	Pepco	$27.8	$12.2	$0.2	$15.9	$0.5	$1.8	($0.2)	($1.5)	$14.4	284	152
3	West	Interface	500	$19.3	$13.3	$0.3	$6.2	($0.0)	($0.0)	($0.0)	$0.0	$6.3	1,758	40
4	Graceton - Raphael Road	Line	BGE	$11.4	$7.8	$0.1	$3.8	($0.2)	$0.0	($0.1)	($0.4)	$3.4	2,324	830
5	Wylie Ridge	Transformer	AP	$11.7	$8.6	$0.3	$3.5	($0.3)	($0.2)	($0.1)	($0.1)	$3.4	3,836	760
6	Bedington - Black Oak	Interface	500	$11.4	$8.4	$0.2	$3.2	($0.0)	($0.0)	($0.0)	$0.0	$3.2	1,358	14
7	Crete - St Johns Tap	Flowgate	MISO	$8.3	$5.8	$0.1	$2.7	($0.2)	($0.0)	($0.1)	($0.3)	$2.4	6,756	2,240
8	Danville - East Danville	Line	AEP	$7.3	$5.1	($0.0)	$2.2	($0.1)	($0.3)	$0.1	$0.2	$2.4	9,264	646
9	AEP - DOM	Interface	500	$7.4	$5.6	$0.1	$2.0	($0.1)	($0.1)	$0.0	$0.0	$2.0	3,578	370
10	5004/5005 Interface	Interface	500	$5.8	$4.1	$0.1	$1.7	($0.0)	($0.1)	($0.1)	($0.1)	$1.6	1,810	940
11	East	Interface	500	($5.1)	($3.9)	($0.1)	($1.3)	$0.0	$0.1	$0.0	($0.1)	($1.4)	1,046	44
12	Gore - Hampshire	Line	AP	$4.3	$3.1	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,654	0
13	East Frankfort - Crete	Line	ComEd	$3.4	$2.2	$0.1	$1.3	($0.0)	($0.0)	($0.1)	($0.1)	$1.2	3,092	658
14	Burnham - Munster	Flowgate	MISO	$3.3	$2.4	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,304	0
15	Glenarm - Windy Edge	Line	BGE	$3.5	$2.5	$0.1	$1.1	($0.1)	($0.1)	($0.1)	($0.1)	$1.0	1,366	316
28	Pumphrey	Transformer	Pepco	($1.5)	($1.1)	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	486	0
54	Burches Hill	Transformer	Pepco	$0.8	$0.5	$0.1	$0.4	$0.1	$0.0	($0.2)	($0.2)	$0.2	136	88
74	Buzzard - Ritchie	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	148	0
91	Burtonsville - Sandy Springs	Line	Pepco	($0.2)	($0.1)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	24	0
194	Dickerson - Pleasant View	Line	Pepco	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	($0.1)	($0.0)	40	20

PPL Control Zone

Table G-24 PPL Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Harwood - Susquehanna	Line	PPL	$2.1	($2.3)	($0.1)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	772	40
2	Graceton - Raphael Road	Line	BGE	($26.5)	($30.7)	($0.7)	$3.5	($0.3)	$0.0	$0.5	$0.2	$3.7	5,328	1,446
3	Harwood - Siegfried	Line	PPL	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.3	($0.4)	($1.3)	($1.3)	0	90
4	5004/5005 Interface	Interface	500	$3.1	$4.1	$0.3	($0.6)	$0.5	$0.3	($0.9)	($0.6)	($1.2)	382	256
5	Hummelstown - Steelton	Line	Met-Ed	$1.4	$0.4	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	80	4
6	Wescosville	Transformer	PPL	$1.9	$1.0	$0.0	$1.0	$0.1	$0.1	($0.0)	$0.0	$1.0	316	62
7	Three Mile Island	Transformer	Met-Ed	$0.4	($0.4)	$0.0	$0.9	$0.2	$0.1	($0.1)	$0.0	$0.9	324	110
8	Juniata	Transformer	PPL	$0.4	($0.1)	$0.2	$0.7	$0.2	($0.0)	($0.2)	$0.0	$0.7	598	76
9	Plymouth Meeting - Whitpain	Line	PECO	($1.1)	($1.5)	($0.1)	$0.3	($0.1)	($0.2)	$0.1	$0.2	$0.6	230	88
10	Palisades - Roosevelt	Flowgate	MISO	$1.6	$2.1	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,710	418
11	West	Interface	500	$16.8	$18.1	$0.7	($0.6)	$0.3	($0.2)	($0.3)	$0.2	($0.4)	1,682	260
12	Clover	Transformer	Dominion	$1.9	$2.3	$0.2	($0.2)	$0.1	$0.1	($0.2)	($0.2)	($0.4)	3,128	904
13	Benton Harbor - Palisades	Flowgate	MISO	$1.4	$1.8	($0.0)	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	1,680	142
14	Sunbury	Transformer	PPL	$0.1	$0.0	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,104	2
15	Graceton - Safe Harbor	Line	BGE	($1.7)	($1.7)	($0.0)	$0.0	($0.3)	$0.3	$0.2	($0.4)	($0.4)	438	194
18	Buxmont - Hosensack	Line	PPL	($0.8)	($1.2)	($0.1)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	216	0
22	Mountain - Wasserot	Line	PPL	($0.0)	($0.0)	$0.3	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	840	0
24	Mountain	Transformer	PPL	$0.1	$0.0	$0.2	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	414	0
25	Martins Creek - Quarry	Line	PPL	($0.1)	($0.4)	($0.0)	$0.3	($0.0)	$0.0	$0.0	$0.0	$0.3	146	0
33	Quarry - Steel City	Line	PPL	$0.0	($0.2)	($0.0)	$0.2	($0.0)	($0.0)	$0.0	$0.0	$0.2	110	2

Table G-25 PPL Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$42.3	$53.4	$1.2	($10.0)	$1.8	$1.3	($0.8)	($0.2)	($10.2)	1,810	940
2	Susquehanna	Transformer	PPL	$16.5	$6.6	$0.2	$10.1	$0.0	$0.0	$0.0	$0.0	$10.1	240	0
3	West	Interface	500	$32.1	$38.0	$1.1	($4.8)	$0.0	($0.1)	($0.0)	$0.1	($4.7)	1,758	40
4	Harwood - Susquehanna	Line	PPL	$0.7	($3.0)	($0.1)	$3.7	($0.4)	$0.2	$0.1	($0.5)	$3.2	310	106
5	Graceton - Raphael Road	Line	BGE	($8.9)	($11.7)	($0.3)	$2.5	($0.1)	$0.1	$0.2	($0.0)	$2.5	2,324	830
6	Wylie Ridge	Transformer	AP	$14.0	$16.7	$0.4	($2.2)	$0.5	$0.1	($0.1)	$0.3	($1.9)	3,836	760
7	AP South	Interface	500	$0.4	($1.0)	$0.5	$1.8	$0.3	$0.1	($0.2)	$0.0	$1.9	8,240	2,026
8	Crete - St Johns Tap	Flowgate	MISO	$7.6	$9.5	$0.0	($1.9)	$0.4	$0.2	($0.0)	$0.2	($1.7)	6,756	2,240
9	Susquehanna	Transformer	PSEG	$0.0	$0.0	$0.0	$0.0	$0.1	($1.5)	($0.2)	$1.4	$1.4	0	104
10	Middletown Jctn. - Three Mile Island	Line	Met-Ed	$1.0	$0.7	$0.0	$0.3	$0.4	($0.7)	($0.0)	$1.1	$1.4	62	30
11	Burnham - Munster	Flowgate	MISO	$3.0	$4.3	($0.0)	($1.3)	$0.0	$0.0	$0.0	$0.0	($1.3)	2,304	0
12	South Mahwah - Waldwick	Line	PSEG	$3.1	$3.9	$0.8	$0.0	$0.2	$0.3	($1.0)	($1.1)	($1.1)	10,538	988
13	East	Interface	500	($0.2)	($1.4)	($0.2)	$1.0	$0.0	$0.0	$0.1	$0.1	$1.0	1,046	44
14	Wescosville	Transformer	PPL	$1.6	$0.9	$0.0	$0.7	$0.3	$0.0	($0.0)	$0.3	$1.0	88	80
15	East Frankfort - Crete	Line	ComEd	$2.7	$3.6	$0.0	($0.9)	$0.0	($0.0)	($0.0)	$0.1	($0.8)	3,092	658
16	Juniata	Transformer	PPL	$0.8	$0.7	$0.1	$0.2	$0.3	$0.3	$0.6	$0.6	$0.7	266	32
50	Mountain	Transformer	PPL	$0.1	($0.2)	$0.0	$0.2	($0.2)	$0.1	($0.1)	($0.4)	($0.1)	134	90
51	Elroy	Transformer	PPL	$0.5	$0.6	$0.0	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	424	0
65	Dauphin - Juniata	Line	PPL	$0.2	$0.1	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	8	0
66	Quarry - Steel City	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	12	34

PSEG Control Zone

Table G-26 PSEG Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Leonia - New Milford	Line	PSEG	$3.0	$3.1	$2.9	$2.8	($0.4)	$0.3	($6.7)	($7.4)	($4.6)	2,696	292
2	Deans	Transformer	PSEG	$0.5	$0.1	$0.4	$0.8	($0.2)	$0.4	($2.5)	($3.0)	($2.3)	370	68
3	Hillsdale - New Milford	Line	PSEG	$1.9	$1.4	$2.4	$2.9	($0.0)	$1.2	($3.9)	($5.2)	($2.3)	2,696	544
4	Readington - Roseland	Line	PSEG	$5.0	$2.5	$0.7	$3.2	$0.0	$0.2	($1.1)	($1.3)	$1.8	2,166	190
5	Cedar Grove - Roseland	Line	PSEG	$0.9	$0.4	$0.3	$0.8	($0.2)	$0.6	($1.8)	($2.6)	($1.7)	1,096	120
6	Graceton - Raphael Road	Line	BGE	($24.9)	($26.4)	($1.3)	$0.1	$0.1	($0.7)	$0.8	$1.5	$1.6	5,328	1,446
7	Northwest	Other	BGE	($5.9)	($6.5)	($0.3)	$0.3	$0.3	($0.4)	$0.7	$1.3	$1.6	1,168	804
8	Maywood - Saddlebrook	Line	PSEG	$0.1	$0.1	($0.0)	($0.1)	($0.1)	$0.1	($1.2)	($1.3)	($1.4)	472	50
9	Farragut - Hudson	Line	PSEG	$0.8	$0.6	$0.9	$1.2	$0.0	$0.0	$0.2	$0.2	$1.4	1,028	8
10	Roseland - Whippany	Line	PSEG	$1.9	$1.0	$0.4	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,794	0
11	Bayway - Federal Square	Line	PSEG	$1.1	($0.4)	$0.4	$1.8	($0.1)	$0.1	($0.3)	($0.5)	$1.3	6,068	96
12	AP South	Interface	500	$1.6	$2.8	$0.4	($0.8)	$0.0	$0.1	($0.4)	($0.4)	($1.2)	5,172	702
13	Bergen - Hoboken	Line	PSEG	$0.0	$0.0	$0.1	$0.1	($0.0)	$0.5	($0.8)	($1.3)	($1.2)	146	140
14	Cedar Grove - Clifton	Line	PSEG	$0.3	$0.1	$0.1	$0.3	$0.0	$0.3	($1.1)	($1.3)	($1.0)	470	120
15	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	$0.0	$1.5	$0.7	$0.1	$0.9	$0.9	36	20
17	Athenia - East Rutherford	Line	PSEG	$1.1	$0.4	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	232	0
18	Hudson	Transformer	PSEG	$0.5	$0.3	$0.5	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,788	0
19	Bergen - Saddlebrook	Line	PSEG	$0.7	$0.5	$0.5	$0.7	$0.0	($0.0)	$0.0	$0.0	$0.7	2,488	28
20	Fairlawn - Saddlebrook	Line	PSEG	$0.1	$0.1	$0.2	$0.2	($0.2)	($0.0)	($0.7)	($0.8)	($0.7)	458	116
25	Roseland - West Caldwell	Line	PSEG	$0.9	$0.6	$0.3	$0.7	$0.0	$0.1	($0.0)	($0.1)	$0.5	1,002	0

Table G-27 PSEG Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	$29.5	$14.6	($7.0)	$7.9	($1.9)	$3.9	($13.0)	($18.8)	($10.9)	10,538	988
2	Waldwick	Transformer	PSEG	$2.1	$1.1	$1.4	$2.4	($0.6)	$0.5	($7.6)	($8.7)	($6.4)	296	186
3	Cedar Grove - Roseland	Line	PSEG	$9.2	$3.9	$0.2	$5.5	($0.1)	$0.7	($0.2)	($0.9)	$4.6	1,842	78
4	AP South	Interface	500	($1.0)	$3.3	$1.5	($2.8)	$0.1	($0.2)	($1.6)	($1.2)	($4.0)	8,240	2,026
5	West	Interface	500	$36.3	$33.9	$1.4	$3.8	($0.1)	$0.1	($0.0)	($0.2)	$3.6	1,758	40
6	Bayway - Federal Square	Line	PSEG	$2.0	($0.6)	$0.2	$2.9	($0.0)	$0.0	($0.0)	($0.1)	$2.8	2,292	30
7	Branchburg - Readington	Line	PSEG	$3.6	$1.2	$0.3	$2.7	($0.1)	$0.4	($0.2)	($0.7)	$2.0	936	108
8	5004/5005 Interface	Interface	500	$33.3	$31.8	$1.5	$2.9	$1.4	$4.4	($1.7)	($4.7)	($1.8)	1,810	940
9	Susquehanna	Transformer	PPL	$1.5	$0.2	$0.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	240	0
10	Roseland - Whippany	Line	PSEG	$2.5	$1.1	$0.3	$1.6	($0.0)	$0.0	($0.4)	($0.5)	$1.2	684	112
11	Plymouth Meeting - Whitpain	Line	PECO	($0.7)	$0.6	$0.0	($1.2)	$0.1	($0.1)	($0.0)	$0.1	($1.1)	412	144
12	Red Oak - Sayreville	Line	JCPL	$1.1	$0.1	$0.1	$1.1	($0.0)	$0.0	($0.0)	($0.0)	$1.1	3,504	22
13	Graceton - Raphael Road	Line	BGE	($8.6)	($8.9)	($0.5)	($0.2)	$0.2	($0.5)	$0.4	$1.2	$0.9	2,324	830
14	Wylie Ridge	Transformer	AP	$12.2	$12.4	$0.7	$0.5	$0.0	$1.0	($0.4)	($1.4)	($0.9)	3,836	760
15	Camden	Transformer	PSEG	$0.9	$0.2	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	840	0
16	Bridgewater - Middlesex	Line	PSEG	$0.5	$0.3	$0.1	$0.3	$0.0	$0.7	($0.4)	($1.1)	($0.8)	1,108	126
17	Hawthorn - Waldwick	Line	PSEG	$0.2	$0.1	$0.6	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,318	0
18	Roseland - West Caldwell	Line	PSEG	$1.5	$0.5	$0.1	$1.1	($0.0)	$0.3	($0.2)	($0.4)	$0.7	264	58
23	Montville - Roseland	Line	PSEG	$1.1	$0.6	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	126	0
24	Athenia - Saddlebrook	Line	PSEG	$0.9	$0.6	$0.3	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	2,812	8

RECO Control Zone

Table G-28 RECO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Graceton - Raphael Road	Line	BGE	($0.6)	($0.0)	($0.0)	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	5,328	1,446
2	West	Interface	500	$0.4	$0.0	$0.0	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	1,682	260
3	Hillsdale - New Milford	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	2,696	544
4	Northwest	Other	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	1,168	804
5	5004/5005 Interface	Interface	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	382	256
6	East	Interface	500	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	418	10
7	Roseland - Whippany	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	1,794	0
8	Readington - Roseland	Line	PSEG	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.1)	($0.1)	$0.1	2,166	190
9	Benton Harbor - Palisades	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,680	142
10	Palisades - Roosevelt	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.0	$0.1	1,710	418
11	Rantoul - Rantoul Jct	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	4,072	630
12	Loudoun - Gainsville	Line	Dominion	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	322	38
13	Buxmont - Whitpain	Line	PECO	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	638	6
14	Crete - St Johns Tap	Flowgate	MISO	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	4,754	554
15	Conastone - Peach Bottom	Line	PECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.1	36	20
373	Burns - Corporate Road	Line	RECO	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	8	0

Table G-29 RECO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	South Mahwah - Waldwick	Line	PSEG	($1.5)	($0.6)	($0.0)	($0.9)	($0.0)	$1.0	$0.0	($1.0)	($1.9)	10,538	988
2	West	Interface	500	$1.0	$0.0	$0.0	$0.9	($0.0)	($0.0)	($0.0)	$0.0	$0.9	1,758	40
3	5004/5005 Interface	Interface	500	$0.9	$0.1	$0.0	$0.8	$0.0	($0.1)	($0.0)	$0.1	$0.9	1,810	940
4	Waldwick	Transformer	PSEG	($0.2)	($0.1)	($0.0)	($0.1)	($0.1)	$0.4	$0.0	($0.4)	($0.5)	296	186
5	East	Interface	500	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,046	44
6	Wylie Ridge	Transformer	AP	$0.3	$0.1	$0.0	$0.3	$0.0	($0.0)	($0.0)	$0.0	$0.3	3,836	760
7	Cedar Grove - Roseland	Line	PSEG	$0.3	$0.1	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.3	1,842	78
8	Crete - St Johns Tap	Flowgate	MISO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	6,756	2,240
9	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,324	830
10	Dickerson - Quince Orchard	Line	Pepco	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.2	284	152
11	AP South	Interface	500	($0.2)	($0.0)	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.0)	($0.2)	8,240	2,026
12	Branchburg - Readington	Line	PSEG	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	936	108
13	Burnham - Munster	Flowgate	MISO	$0.1	$0.0	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,304	0
14	Glenarm - Windy Edge	Line	BGE	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.1)	1,366	316
15	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	($0.0)	$0.1	3,092	658

Western Region Congestion-Event Summaries

AEP Control Zone

Table G-30 AEP Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Monticello - East Winamac	Flowgate	MISO	$1.6	($14.6)	($2.1)	$14.2	$0.3	$1.5	($0.5)	($1.7)	$12.4	5,468	1,156
2	Breed - Wheatland	Flowgate	MISO	$0.9	($12.0)	($4.6)	$8.3	$0.3	$0.3	$3.1	$3.0	$11.3	5,642	856
3	AP South	Interface	500	($28.9)	($39.2)	($1.8)	$8.5	$2.0	$2.4	$2.8	$2.4	$11.0	5,172	702
4	Kammer	Transformer	AEP	$4.8	($2.8)	$1.4	$9.0	($0.2)	$0.0	($0.1)	($0.3)	$8.7	7,332	38
5	AEP - DOM	Interface	500	($3.9)	($14.3)	$0.6	$10.9	$0.7	$3.3	($0.6)	($3.1)	$7.8	4,190	122
6	Brues - West Bellaire	Line	AEP	$3.2	($0.3)	$0.7	$4.2	($0.1)	$0.1	($0.1)	($0.2)	$3.9	3,132	140
7	Kenova - Tri State	Line	AEP	$0.4	($3.4)	$0.1	$3.9	($0.0)	$0.1	$0.1	$0.0	$3.9	940	52
8	Cumberland - Bush	Flowgate	MISO	$1.0	($3.5)	($0.5)	$4.0	$0.1	$0.9	$0.5	($0.3)	$3.7	4,106	632
9	West	Interface	500	($23.8)	($26.9)	($0.4)	$2.7	$0.7	$0.8	$0.3	$0.3	$3.0	1,682	260
10	Sporn	Transformer	AEP	$0.3	($0.5)	$2.1	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	38,672	0
11	Big Sandy - Grangston	Line	AEP	$0.3	$0.0	$2.2	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	6,132	0
12	Bedington - Black Oak	Interface	500	($10.9)	($13.3)	($0.4)	$1.9	$0.2	$0.1	$0.2	$0.3	$2.2	1,560	108
13	Ruth - Turner	Line	AEP	$1.3	($1.0)	($0.1)	$2.2	$0.0	$0.1	($0.0)	($0.1)	$2.1	668	156
14	Belvidere - Woodstock	Line	ComEd	($0.1)	($0.1)	$0.3	$0.3	$0.0	$0.0	($2.4)	($2.4)	($2.1)	1,760	1,532
15	Benton Harbor - Palisades	Flowgate	MISO	($2.7)	($4.9)	($0.2)	$2.0	$0.1	$0.0	$0.0	$0.1	$2.1	1,680	142
21	Sullivan	Transformer	AEP	($0.2)	($1.5)	($0.3)	$1.0	$0.0	($0.0)	$0.2	$0.2	$1.3	1,704	100
23	Muskingum River - Waterford	Line	AEP	($0.6)	($1.9)	$0.8	$2.1	$0.0	$0.2	($0.8)	($1.0)	$1.2	1,324	82
26	Muskingum River	Transformer	AEP	$0.1	($0.6)	$0.4	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	1,454	0
29	Breed - Wheatland	Line	AEP	$0.2	($1.3)	($0.4)	$1.1	$0.0	($0.0)	$0.0	$0.0	$1.1	244	0
34	Michigan City - Laporte	Line	AEP	$0.0	$0.0	$0.0	$0.0	($0.5)	($0.0)	($0.6)	($1.1)	($1.0)	48	0

Table G-31 AEP Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($113.5)	($148.9)	($1.3)	$34.1	$3.7	$6.9	$2.3	($1.0)	$33.1	8,240	2,026
2	Belmont	Transformer	AP	$13.1	($15.0)	$4.9	$33.1	($2.0)	($0.3)	($3.9)	($5.6)	$27.5	8,750	998
3	AEP - DOM	Interface	500	($13.9)	($37.1)	$2.5	$25.7	$0.6	$1.5	($0.7)	($1.6)	$24.1	3,578	370
4	Brues - West Bellaire	Line	AEP	$21.7	$6.3	$1.9	$17.3	($2.1)	$1.7	($2.0)	($5.8)	$11.5	3,436	1,196
5	5004/5005 Interface	Interface	500	($65.3)	($76.4)	($0.8)	$10.3	$2.9	$3.9	$1.3	$0.3	$10.7	1,810	940
6	West	Interface	500	($56.9)	($68.0)	($0.6)	$10.4	$0.0	$0.1	$0.0	($0.0)	$10.4	1,758	40
7	Breed - Wheatland	Line	AEP	$1.2	($7.4)	($1.0)	$7.6	($0.0)	($0.0)	($0.0)	$0.0	$7.6	2,484	2
8	Michigan City - Laporte	Flowgate	MISO	$15.2	$8.9	$4.3	$10.6	($3.1)	($1.7)	($3.9)	($5.4)	$5.2	5,870	1,264
9	Kammer	Transformer	AEP	$5.5	($2.8)	$1.2	$9.4	($3.4)	($0.3)	($1.3)	($4.4)	$5.1	2,578	138
10	Wolfcreek	Transformer	AEP	($8.9)	($14.2)	$1.4	$6.7	($0.1)	$0.5	($1.2)	($1.9)	$4.8	5,122	452
11	Wylie Ridge	Transformer	AP	($42.9)	($49.0)	($1.3)	$4.8	$0.5	$1.3	$0.6	($0.2)	$4.6	3,836	760
12	Bedington - Black Oak	Interface	500	($16.5)	($20.8)	($0.1)	$4.2	$0.1	$0.0	$0.0	$0.0	$4.2	1,358	14
13	Danville - East Danville	Line	AEP	($30.1)	($29.9)	($5.4)	($5.6)	$1.1	$1.6	$1.9	$1.4	($4.1)	9,264	646
14	Cloverdale	Transformer	AEP	($4.5)	($8.8)	$0.4	$4.7	$0.2	$0.8	($0.0)	($0.7)	$4.1	1,402	250
15	Muskingum River	Transformer	AEP	($0.5)	($3.9)	$0.5	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	636	0
17	Marquis - Dept of Energy	Line	AEP	$0.1	($0.3)	$3.2	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,998	0
19	Muskingum River - East New Concord	Line	AEP	$0.7	($1.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	218	0
21	Jefferson - Clifty Creek	Line	AEP	($0.1)	($3.1)	($0.4)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	582	0
23	Carbondale - Kanawha River	Line	AEP	($3.5)	($5.6)	$0.2	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	548	0
25	Muskingum River - Waterford	Line	AEP	($1.0)	($2.8)	$1.5	$3.3	$0.2	$0.8	($0.5)	($1.1)	$2.2	1,066	106

AP Control Zone

Table G-32 AP Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($6.0)	($28.8)	$0.3	$23.1	$1.8	$4.2	($0.7)	($3.2)	$19.9	5,172	702
2	Bedington - Black Oak	Interface	500	($1.7)	($9.8)	($0.5)	$7.6	$0.3	$0.5	$0.0	($0.1)	$7.5	1,560	108
3	West	Interface	500	($8.4)	($11.8)	($0.7)	$2.8	$0.1	$0.7	$0.4	($0.2)	$2.6	1,682	260
4	Belmont	Transformer	AP	$3.0	($0.3)	$0.3	$3.6	($0.1)	$0.7	($0.4)	($1.2)	$2.5	3,666	120
5	Stephenson - Stonewall	Line	AP	$1.4	($0.5)	($0.2)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	538	42
6	AEP - DOM	Interface	500	($0.2)	($1.5)	$0.1	$1.3	($0.0)	$0.1	$0.4	$0.3	$1.6	4,190	122
7	Clover	Transformer	Dominion	$0.9	($0.2)	$1.1	$2.1	$0.2	$0.1	($1.4)	($1.2)	$0.9	3,128	904
8	Loudoun - Gainsville	Line	Dominion	$0.5	($0.3)	$0.1	$0.9	$0.0	$0.0	($0.1)	($0.0)	$0.9	322	38
9	Kammer	Transformer	AEP	$0.4	($0.3)	$0.3	$0.9	($0.0)	($0.0)	($0.0)	($0.0)	$0.9	7,332	38
10	Doubs - Mount Storm	Line	500	($0.1)	($0.8)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	160	0
11	Hunterstown	Transformer	Met-Ed	($0.1)	($0.8)	$0.1	$0.8	$0.0	$0.2	($0.1)	($0.2)	$0.6	1,396	136
12	Gardners - Texas East	Line	Met-Ed	$0.5	$0.1	$0.2	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.6	1,186	74
13	Garretts Run - Kiski Valley	Line	AP	$0.1	($0.9)	($0.1)	$0.9	($0.2)	$0.2	$0.1	($0.3)	$0.6	840	206
14	Tiltonsville - Windsor	Line	AP	$0.8	$0.3	$0.1	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	1,464	14
15	Belvidere - Woodstock	Line	ComEd	($0.0)	($0.1)	$0.1	$0.1	($0.0)	($0.0)	($0.7)	($0.6)	($0.6)	1,760	1,532
17	Shaffer - Springdale	Line	AP	$0.0	($0.5)	($0.1)	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	410	112
20	Butler - Karns City	Line	AP	$0.4	$0.0	($0.0)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	686	18
24	All Dam - Kittanning	Line	AP	($0.0)	($0.4)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	250	90
25	Bedington - Marlowe	Line	AP	$0.1	($0.3)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	80	0
28	Kingwood - Pruntytown	Line	AP	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	124	0

Table G-33 AP Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($26.3)	($91.6)	($7.8)	$57.6	$5.5	$5.7	$6.5	$6.3	$63.9	8,240	2,026
2	Belmont	Transformer	AP	$34.3	$7.2	$0.9	$28.0	($2.4)	($3.3)	($0.6)	$0.3	$28.3	8,750	998
3	5004/5005 Interface	Interface	500	($20.2)	($29.7)	($3.8)	$5.7	$1.4	$1.7	$4.4	$4.0	$9.7	1,810	940
4	Bedington - Black Oak	Interface	500	($3.1)	($11.6)	($1.9)	$6.5	$0.0	$0.1	$0.1	$0.1	$6.6	1,358	14
5	Yukon	Transformer	AP	$4.4	$0.0	$0.2	$4.6	$0.2	$0.4	($0.1)	($0.3)	$4.3	750	180
6	AEP - DOM	Interface	500	($1.3)	($4.7)	($0.0)	$3.3	$0.1	$0.1	$0.3	$0.4	$3.7	3,578	370
7	Bedington	Transformer	AP	$1.2	($2.7)	($0.2)	$3.6	($0.1)	$0.6	$0.3	($0.4)	$3.2	464	206
8	Wylie Ridge	Transformer	AP	$6.0	$9.7	$3.7	($0.0)	($0.1)	($0.3)	($3.1)	($2.9)	($2.9)	3,836	760
9	West	Interface	500	($18.5)	($24.4)	($3.2)	$2.6	$0.1	$0.0	$0.1	$0.1	$2.8	1,758	40
10	Wolfcreek	Transformer	AEP	$5.7	$8.2	$1.0	($1.5)	($0.5)	($0.6)	($1.0)	($0.9)	($2.4)	5,122	452
11	Tiltonsville - Windsor	Line	AP	$2.6	$0.7	$0.3	$2.1	($0.2)	($0.0)	($0.2)	($0.4)	$1.7	2,036	144
12	Dickerson - Quince Orchard	Line	Pepco	($6.8)	($5.2)	($0.9)	($2.5)	($0.8)	($0.2)	$1.3	$0.8	($1.7)	284	152
13	Mount Storm	Line	AP	($0.4)	($1.9)	$0.2	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	162	0
14	Danville - East Danville	Line	AEP	$0.3	($1.1)	$0.2	$1.5	$0.1	$0.0	$0.0	$0.1	$1.6	9,264	646
15	Valley	Transformer	Dominion	($0.8)	($2.0)	($0.0)	$1.2	$0.3	$0.2	$0.1	$0.2	$1.4	438	196
16	Gore - Hampshire	Line	AP	($2.1)	($3.8)	($0.4)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	1,654	0
19	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	$0.6	$1.1	($0.6)	($1.1)	($1.1)	0	218
21	Kingwood - Pruntytown	Line	AP	$0.8	($0.1)	$0.1	$0.9	($0.0)	($0.1)	($0.0)	($0.0)	$0.9	426	28
25	Hamilton - Weirton	Line	AP	$1.0	$0.3	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	304	6
26	Halfway - Marlowe	Line	AP	$0.5	($0.2)	$0.0	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	158	18

ATSI Control Zone

Table G-34 ATSI Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($22.4)	($20.9)	($0.3)	($1.8)	$0.4	$1.6	$0.4	($0.7)	($2.5)	5,172	702
2	Highland - Salt Springs	Line	ATSI	$2.2	($0.0)	($0.1)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	56	0
3	Lakeview - Ottawa	Line	ATSI	$1.2	($1.0)	$0.0	$2.2	$0.1	$0.2	($0.0)	($0.1)	$2.1	200	40
4	Bedington - Black Oak	Interface	500	($7.0)	($5.4)	($0.1)	($1.8)	$0.2	$0.1	$0.0	$0.0	($1.7)	1,560	108
5	West	Interface	500	($12.0)	($10.9)	($0.1)	($1.1)	$0.1	$0.4	$0.0	($0.2)	($1.3)	1,682	260
6	Crescent	Transformer	DLCO	($3.1)	($4.5)	($0.2)	$1.2	$0.0	$0.1	$0.0	($0.0)	$1.2	590	60
7	Rantoul - Rantoul Jct	Flowgate	MISO	$3.0	$2.5	$0.3	$0.9	($0.0)	($0.0)	$0.1	$0.1	$1.0	4,072	630
8	Niles - Evergreen	Line	ATSI	$1.4	$0.3	$0.0	$1.2	($0.2)	$0.1	$0.0	($0.2)	$0.9	330	58
9	Lemoyne - Bowling Green	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$1.6	$1.2	($0.0)	$0.4	$0.9	234	414
10	AEP - DOM	Interface	500	($3.8)	($3.3)	($0.1)	($0.5)	($0.0)	$0.2	$0.0	($0.2)	($0.7)	4,190	122
11	Clover	Transformer	Dominion	($3.1)	($2.6)	$0.1	($0.4)	$0.0	$0.1	($0.0)	($0.1)	($0.5)	3,128	904
12	Prairie State - W Mt. Vernon	Flowgate	MISO	$1.5	$1.3	$0.2	$0.5	$0.0	($0.0)	$0.0	$0.0	$0.5	2,966	2,022
13	Brookside - Troy	Line	ATSI	$0.3	$0.1	$0.0	$0.2	($0.4)	$0.2	($0.1)	($0.7)	($0.5)	222	62
14	Crete - St Johns Tap	Flowgate	MISO	$3.3	$3.0	$0.2	$0.5	($0.0)	($0.0)	($0.1)	($0.0)	$0.4	4,754	554
15	Rising	Flowgate	MISO	$0.6	$0.5	$0.0	$0.1	($0.0)	($0.0)	$0.2	$0.2	$0.4	816	726
21	Lemoyne	Transformer	ATSI	$0.0	$0.0	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.3	$0.3	0	22
23	Lakeview - Greenfoe	Line	ATSI	$0.2	($0.4)	$0.1	$0.7	$0.0	$0.4	($0.1)	($0.4)	$0.3	344	132
36	Clover - Ross	Line	ATSI	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	270	0
45	Ottawa - West Freemont	Line	ATSI	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	38	14
60	Inland - Pofok Tie	Line	ATSI	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	88	2

Table G-35 ATSI Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($27.8)	($27.1)	($1.3)	($2.0)	($0.2)	$2.4	$1.8	($0.8)	($2.9)	8,240	2,026
2	Niles - Evergreen	Line	ATSI	$3.2	$0.8	$0.8	$3.2	($0.4)	$0.2	($0.6)	($1.2)	$1.9	892	54
3	Dickerson - Quince Orchard	Line	Pepco	($4.2)	($3.5)	$0.0	($0.7)	($0.2)	$0.4	($0.0)	($0.6)	($1.3)	284	152
4	West	Interface	500	($21.8)	($20.7)	($0.1)	($1.2)	($0.0)	$0.0	$0.0	($0.0)	($1.2)	1,758	40
5	Bayshore - Jeep	Line	ATSI	$0.8	($0.2)	$0.0	$1.0	$0.4	$0.2	$0.0	$0.2	$1.2	32	12
6	Clover	Transformer	Dominion	($2.8)	($2.3)	$0.4	($0.2)	$0.2	$0.4	($0.6)	($0.8)	($1.0)	2,476	938
7	Beaver - Sammis	Line	DLCO	($0.5)	($1.5)	($0.1)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	442	22
8	Burnham - Munster	Flowgate	MISO	$4.5	$3.7	$0.1	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	2,304	0
9	South Canton - Torrey	Line	AEP	$1.4	$0.6	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	82	16
10	Danville - East Danville	Line	AEP	($3.8)	($3.3)	($0.2)	($0.8)	$0.1	$0.1	$0.1	$0.0	($0.8)	9,264	646
11	5004/5005 Interface	Interface	500	($5.0)	($5.1)	($0.1)	($0.0)	$0.2	$1.2	$0.2	($0.7)	($0.8)	1,810	940
12	Muskingum River - Waterford	Line	AEP	$0.8	$0.7	$0.1	$0.1	$0.1	($0.1)	($1.0)	($0.7)	($0.6)	1,066	106
13	AEP - DOM	Interface	500	($4.4)	($3.8)	($0.1)	($0.8)	$0.0	$0.1	$0.2	$0.2	($0.6)	3,578	370
14	Benton Harbor - Palisades	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.0)	($0.4)	($0.6)	($0.6)	134	264
15	Jeep - Dixie	Line	ATSI	$0.4	($0.1)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	28	0
20	Sammis - Wylie Ridge	Line	ATSI	($1.2)	($1.8)	($0.2)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	484	8
29	Lakeview - Ottawa	Line	ATSI	$0.2	($0.0)	$0.0	$0.2	$0.0	$0.0	($0.0)	$0.0	$0.3	46	4
31	Galion – GM Mansfield	Line	ATSI	$0.3	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	36	0
35	Galion - Leaside	Line	ATSI	$0.1	$0.1	$0.0	$0.1	$0.1	($0.0)	($0.0)	$0.1	$0.2	44	22
42	Brookside - Wellington	Line	ATSI	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	224	0

ComEd Control Zone

Table G-36 ComEd Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	Flowgate	MISO	($3.9)	($29.3)	$7.5	$32.9	$0.0	$0.0	$0.0	$0.0	$32.9	2,146	0
2	Nelson - Cordova	Line	ComEd	$8.3	($9.4)	$7.3	$25.1	$0.4	$1.3	($6.5)	($7.4)	$17.7	5,286	576
3	Rantoul - Rantoul Jct	Flowgate	MISO	($39.7)	($52.1)	($1.0)	$11.4	$0.3	($0.2)	($0.8)	($0.3)	$11.1	4,072	630
4	Oak Grove - Galesburg	Flowgate	MISO	($13.0)	($26.0)	$7.8	$20.9	$0.3	$1.7	($9.1)	($10.5)	$10.4	7,244	2,718
5	Prairie State - W Mt. Vernon	Flowgate	MISO	($23.3)	($32.0)	$0.0	$8.8	$0.1	($0.1)	($0.0)	$0.2	$8.9	2,966	2,022
6	Belvidere - Woodstock	Line	ComEd	$0.3	($7.5)	($0.0)	$7.8	($0.7)	$4.1	($11.1)	($15.9)	$8.0	1,760	1,532
7	Pleasant Valley - Belvidere	Line	ComEd	($1.8)	($8.5)	$0.9	$7.6	$0.1	$0.1	($0.4)	($0.3)	$7.2	1,440	102
8	Dixon - Stillman Valley	Line	ComEd	$2.8	($3.5)	$0.9	$7.2	$0.2	$0.9	($0.6)	($1.3)	$6.0	3,896	212
9	Crete - St Johns Tap	Flowgate	MISO	($44.3)	($58.6)	($8.5)	$5.9	$0.6	$0.8	$0.1	($0.1)	$5.8	4,754	554
10	Beaver Channel - Albany	Flowgate	MISO	$8.4	($4.0)	$4.3	$16.7	($4.8)	($0.3)	($6.6)	($11.0)	$5.7	2,512	992
11	Hegewisch - Burnham	Line	ComEd	($9.9)	($15.0)	($1.0)	$4.2	($0.5)	$0.5	$2.0	$1.0	$5.2	2,252	576
12	AP South	Interface	500	($29.3)	($32.8)	($0.6)	$2.9	$1.9	$0.4	$0.8	$2.3	$5.1	5,172	702
13	Electric Jct - Nelson	Line	ComEd	($0.6)	($4.0)	$1.6	$5.0	$0.0	$0.0	($0.0)	($0.0)	$5.0	1,272	10
14	Silver Lake - Pleasant Valley	Line	ComEd	($2.6)	($6.0)	$0.9	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	2,238	0
15	East Frankfort - Braidwood	Line	ComEd	($0.7)	($4.5)	($0.2)	$3.7	($0.0)	$0.7	$0.9	$0.2	$3.9	632	98
17	Mazon - Mazon	Line	ComEd	$0.7	($1.6)	$1.5	$3.8	($0.1)	$0.1	($0.5)	($0.7)	$3.1	1,524	340
18	Belvidere - Chrysler Corp.	Line	ComEd	$0.3	($3.8)	($1.1)	$3.0	($0.0)	($0.0)	($0.0)	($0.0)	$3.0	726	2
19	Cherry Valley	Transformer	ComEd	$0.9	($2.2)	$0.0	$3.2	($0.0)	$0.4	($0.5)	($0.9)	$2.3	1,110	84
20	Lancaster - Maryland	Line	ComEd	$0.3	($0.2)	$0.2	$0.7	($0.3)	$0.7	($1.9)	($2.9)	$2.2	282	24
23	Nelson	Transformer	ComEd	($0.2)	($1.7)	$0.5	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	954	0

Table G-37 ComEd Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Electric Jct - Nelson	Line	ComEd	($5.1)	($43.6)	$6.2	$44.8	$1.2	$4.0	($5.1)	($7.9)	$36.9	5,886	316
2	Crete - St Johns Tap	Flowgate	MISO	($156.4)	($190.6)	($16.6)	$17.6	$7.0	$5.6	$7.6	$8.9	$26.5	6,756	2,240
3	AP South	Interface	500	($122.0)	($134.5)	($0.9)	$11.6	$7.6	$2.5	$0.3	$5.5	$17.1	8,240	2,026
4	East Frankfort - Crete	Line	ComEd	($56.3)	($71.2)	($5.0)	$10.0	$1.5	$0.5	$2.1	$3.1	$13.1	3,092	658
5	Bunsonville - Eugene	Flowgate	MISO	($39.8)	($51.0)	($0.1)	$11.1	$0.0	$0.0	($0.0)	($0.0)	$11.1	4,888	22
6	Pleasant Valley - Belvidere	Line	ComEd	($5.3)	($17.4)	$1.2	$13.3	($0.3)	$2.2	($1.3)	($3.8)	$9.5	2,214	630
7	5004/5005 Interface	Interface	500	($62.7)	($69.3)	($0.4)	$6.2	$4.0	$2.0	$0.5	$2.5	$8.7	1,810	940
8	Wylie Ridge	Transformer	AP	($38.5)	($43.2)	($0.1)	$4.6	$1.6	$0.4	($0.1)	$1.1	$5.7	3,836	760
9	Michigan City - Laporte	Flowgate	MISO	($40.7)	($43.4)	$1.7	$4.3	$2.5	$0.5	($1.0)	$1.0	$5.4	5,870	1,264
10	Lakeview - Pleasant Prairie	Flowgate	MISO	$0.3	$0.2	$0.2	$0.3	($0.3)	($0.0)	($4.8)	($5.1)	($4.8)	48	604
11	Brokaw - Gibson	Flowgate	MISO	($15.1)	($19.7)	$0.5	$5.2	$0.2	$0.1	($0.6)	($0.5)	$4.7	1,418	190
12	Waukegan - Zion	Line	ComEd	$0.7	($1.2)	$2.9	$4.8	$0.0	$0.0	($0.3)	($0.3)	$4.5	3,468	14
13	Pleasant Prairie - Zion	Flowgate	MISO	$0.1	($1.0)	$1.2	$2.3	$0.0	$0.1	($6.7)	($6.8)	($4.5)	672	420
14	Rantoul - Rantoul Jct	Flowgate	MISO	($14.3)	($18.3)	$0.0	$3.9	$0.3	$0.1	$0.1	$0.3	$4.2	1,106	376
15	Cherry Valley	Transformer	ComEd	$1.7	($1.8)	$0.5	$3.9	$0.1	$0.1	($0.2)	($0.2)	$3.7	1,406	164
17	Glidden - West Dekalb	Line	ComEd	($0.7)	($3.9)	$0.3	$3.5	$0.0	($0.0)	($0.0)	($0.0)	$3.5	2,238	2
20	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$1.2	($0.1)	$1.7	$3.0	$3.0	0	454
22	Wilton Center	Transformer	ComEd	($1.6)	($1.9)	$2.5	$2.8	$0.1	$0.1	$0.0	$0.0	$2.9	134	52
24	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.0)	$0.3	$3.3	$0.0	$0.2	($0.2)	($0.5)	$2.8	378	86
26	Woodstock - 12205	Line	ComEd	($0.7)	($3.1)	$0.2	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	790	0

DAY Control Zone

Table G-38 DAY Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Stuart - Killen	Line	DAY	$0.1	$0.1	$0.8	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	714	0
2	Foster2 - Pierce	Line	DAY	$0.7	$0.5	$0.7	$0.9	($0.0)	$0.0	($0.1)	($0.1)	$0.8	2,964	22
3	Rantoul - Rantoul Jct	Flowgate	MISO	$0.9	$0.9	$0.6	$0.6	$0.0	($0.0)	($0.1)	($0.1)	$0.6	4,072	630
4	Kyger Creek - DOE	Line	EXT	($0.0)	($0.0)	$0.5	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,076	0
5	AP South	Interface	500	($4.4)	($4.2)	($0.1)	($0.3)	$0.1	$0.3	$0.1	($0.1)	($0.4)	5,172	702
6	Belvidere - Woodstock	Line	ComEd	($0.0)	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.4)	($0.4)	($0.3)	1,760	1,532
7	Rantoul Jct - Sidney	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	662
8	Crete - St Johns Tap	Flowgate	MISO	$0.8	$0.7	$0.3	$0.4	$0.0	($0.0)	($0.2)	($0.1)	$0.3	4,754	554
9	Nelson - Cordova	Line	ComEd	($0.4)	($0.5)	$0.4	$0.5	($0.0)	$0.0	($0.3)	($0.3)	$0.2	5,286	576
10	West	Interface	500	($3.0)	($2.9)	($0.0)	($0.2)	$0.1	$0.2	$0.0	($0.1)	($0.2)	1,682	260
11	Woodstock	Flowgate	MISO	($0.0)	($0.0)	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	2,146	0
12	Breed - Wheatland	Flowgate	MISO	$0.8	$0.8	$0.3	$0.3	$0.0	($0.0)	($0.1)	($0.0)	$0.2	5,642	856
13	Toddhunt - Trenton	Line	DEOK	($0.0)	($0.5)	($0.2)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,286	0
14	Rising	Flowgate	MISO	$0.2	$0.3	$0.1	$0.1	$0.0	($0.0)	($0.3)	($0.3)	($0.2)	816	726
15	Palisades - Roosevelt	Flowgate	MISO	($0.3)	($0.4)	$0.1	$0.2	($0.0)	$0.0	($0.1)	($0.1)	$0.2	1,710	418
22	Stuart - Clinton	Line	DAY	$0.1	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	80	0
57	Trenton - Hutchings	Line	DAY	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	96	0
61	Stuart - Atlanta	Line	DAY	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	104	0
64	Hillcrest - Stuart	Line	DAY	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	114	0
100	Darby - Watkins Tap	Line	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	136	0

Table G-39 DAY Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pierce - Foster	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.2)	($1.7)	($1.6)	($1.6)	0	40
2	West	Interface	500	($7.3)	($8.7)	($0.0)	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1,758	40
3	AP South	Interface	500	($16.1)	($17.7)	($0.4)	$1.2	$0.8	$1.5	$0.5	($0.2)	$1.0	8,240	2,026
4	AEP - DOM	Interface	500	($3.7)	($4.7)	($0.0)	$0.9	$0.1	$0.2	$0.1	$0.0	$0.9	3,578	370
5	Danville - East Danville	Line	AEP	($2.5)	($3.4)	($0.1)	$0.8	$0.1	$0.2	$0.0	($0.1)	$0.8	9,264	646
6	Burnham - Munster	Flowgate	MISO	$1.1	$1.7	$0.1	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	2,304	0
7	Clover	Transformer	Dominion	($1.9)	($2.4)	$0.1	$0.6	$0.2	$0.2	($0.1)	($0.1)	$0.5	2,476	938
8	Crete - St Johns Tap	Flowgate	MISO	$2.8	$3.1	($0.1)	($0.4)	($0.1)	($0.1)	($0.2)	($0.1)	($0.5)	6,756	2,240
9	East Frankfort - Crete	Line	ComEd	$1.0	$1.4	$0.1	($0.3)	($0.0)	$0.0	($0.1)	($0.1)	($0.5)	3,092	658
10	Breed - Wheatland	Line	AEP	$0.5	$0.9	($0.0)	($0.4)	($0.0)	($0.0)	($0.0)	($0.0)	($0.4)	2,484	2
11	Wolfcreek	Transformer	AEP	($1.7)	($2.1)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	5,122	452
12	Bunsonville - Eugene	Flowgate	MISO	$1.7	$2.2	$0.1	($0.4)	$0.0	($0.0)	($0.0)	$0.0	($0.4)	4,888	22
13	Valley	Transformer	Dominion	($0.9)	($1.3)	($0.0)	$0.4	$0.1	$0.2	$0.0	($0.0)	$0.3	438	196
14	Belmont	Transformer	AP	($1.5)	($1.8)	$0.1	$0.4	$0.0	$0.1	($0.0)	($0.1)	$0.3	8,750	998
15	Brokaw - Gibson	Flowgate	MISO	$0.4	$0.8	$0.0	($0.3)	($0.0)	($0.0)	($0.0)	($0.0)	($0.3)	1,418	190

DEOK Control Zone

Table G-40 DEOK Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Miami Fort - Hebron	Flowgate	MISO	$2.9	$0.5	$0.2	$2.6	($0.2)	($0.0)	($0.1)	($0.2)	$2.4	2,106	152
2	Beckjord - Pierce	Line	DEOK	$1.9	$0.6	$0.4	$1.8	$0.2	($0.0)	($0.4)	($0.2)	$1.6	700	96
3	Graceton - Raphael Road	Line	BGE	$2.1	$1.2	($0.0)	$0.9	$0.0	($0.1)	$0.0	$0.1	$1.0	5,328	1,446
4	Clover	Transformer	Dominion	($2.8)	($2.1)	$0.0	($0.7)	$0.0	$0.1	($0.0)	($0.2)	($0.8)	3,128	904
5	Bedington - Black Oak	Interface	500	($2.0)	($1.5)	($0.0)	($0.6)	$0.0	$0.2	$0.0	($0.2)	($0.8)	1,560	108
6	West	Interface	500	($4.0)	($3.3)	($0.0)	($0.8)	$0.1	$0.0	$0.0	$0.1	($0.7)	1,682	260
7	Toddhunt - Trenton	Line	DEOK	$0.2	($0.5)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,286	0
8	AEP - DOM	Interface	500	($1.9)	($1.5)	$0.0	($0.3)	($0.1)	$0.1	($0.1)	($0.2)	($0.6)	4,190	122
9	AP South	Interface	500	($5.6)	($4.8)	($0.1)	($0.8)	$0.2	($0.0)	$0.1	$0.3	($0.5)	5,172	702
10	Miami Fort	Transformer	DEOK	$0.6	$0.2	$0.2	$0.5	$0.0	($0.0)	($0.1)	($0.1)	$0.5	2,544	104
11	Foster2 - Pierce	Line	DAY	$0.5	$0.4	$0.4	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	2,964	22
12	Rantoul - Rantoul Jct	Flowgate	MISO	$1.3	$0.9	$0.2	$0.5	($0.0)	($0.0)	($0.1)	($0.1)	$0.4	4,072	630
13	Hebron - Constance	Line	DEOK	$0.4	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	550	0
14	Loudoun - Gainsville	Line	Dominion	($0.9)	($0.6)	($0.0)	($0.3)	$0.0	$0.0	$0.0	($0.0)	($0.3)	322	38
15	Crete - St Johns Tap	Flowgate	MISO	$1.1	$0.9	$0.1	$0.3	$0.0	($0.0)	($0.1)	($0.0)	$0.3	4,754	554
19	Silver Grove	Other	DEOK	$0.1	($0.1)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	354	0
22	Miami Fort - Miami Fort	Line	DEOK	$0.1	$0.1	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	154	0
27	Miami Fort- Terminal	Line	DEOK	($0.0)	$0.0	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	324	0
37	Todd Hunter - Trenton	Line	DEOK	$0.1	($0.0)	$0.0	$0.1	($0.1)	$0.1	($0.1)	($0.2)	($0.1)	110	0
47	Rochelle - Terminal	Line	DEOK	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	16	0

DLCO Control Zone

Table G-41 DLCO Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$3.9	($0.2)	$0.2	$4.2	$0.1	$0.0	($0.1)	($0.0)	$4.2	590	60
2	Brunot Island - Montour	Line	DLCO	$1.2	($0.4)	$0.1	$1.8	($0.0)	$0.4	($0.2)	($0.6)	$1.2	772	418
3	AP South	Interface	500	($5.8)	($6.5)	($0.2)	$0.6	$0.0	$0.0	$0.2	$0.2	$0.8	5,172	702
4	Crescent - Montour	Line	DLCO	$0.4	($0.3)	($0.0)	$0.6	($0.0)	$0.1	($0.1)	($0.2)	$0.5	202	46
5	Beaver - Clinton	Line	DLCO	$0.2	($0.3)	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	228	0
6	Collier	Transformer	DLCO	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	82	38
7	Clinton - Findlay	Line	DLCO	$0.3	$0.0	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	146	0
8	Arsenal - Brunot Island	Line	DLCO	$0.4	$0.2	$0.1	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	230	6
9	St. Joe	Other	DLCO	$0.2	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	1,426	0
10	Carson - Homested	Line	DLCO	$0.2	($0.0)	$0.0	$0.2	$0.0	($0.0)	($0.0)	($0.0)	$0.2	42	2
11	Elrama - Dravosburg	Line	DLCO	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	($0.0)	$0.2	$0.2	0	20
12	Crescent - Mansfield	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	16
13	Bedington - Black Oak	Interface	500	($2.0)	($1.8)	($0.1)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	1,560	108
14	West	Interface	500	($3.2)	($3.4)	($0.1)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.2	1,682	260
15	Tiltonsville - Windsor	Line	AP	$0.3	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	1,464	14
20	Crescent - Sewickly	Line	DLCO	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	20	0
23	Carson - Oakland	Line	DLCO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	28	4
34	Neville Tap - Sewickley	Line	DLCO	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	18	0
74	Beaver - Sammis	Line	DLCO	($0.0)	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	98	0
78	Brunot Island - Neville	Line	DLCO	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	16	0

Table G-42 DLCO Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crescent	Transformer	DLCO	$5.9	($0.4)	$0.1	$6.4	($0.1)	$0.1	($0.2)	($0.4)	$6.0	714	206
2	Wylie Ridge	Transformer	AP	($11.5)	($16.8)	($0.4)	$4.8	($0.4)	($0.1)	$0.2	($0.2)	$4.7	3,836	760
3	AP South	Interface	500	($18.6)	($23.3)	($0.5)	$4.1	($1.3)	$0.0	$0.4	($0.9)	$3.3	8,240	2,026
4	Collier - Elwyn	Line	DLCO	$1.8	($0.2)	$0.0	$2.0	$0.1	$0.1	($0.0)	($0.0)	$1.9	504	60
5	Brunot Island - Forbes	Line	DLCO	$0.7	($0.1)	$0.0	$0.8	($0.0)	($0.1)	($0.0)	$0.0	$0.8	172	72
6	Yukon	Transformer	AP	$2.0	$1.5	$0.1	$0.5	$0.3	($0.2)	($0.2)	$0.3	$0.8	750	180
7	AEP - DOM	Interface	500	($1.8)	($2.6)	$0.0	$0.8	($0.1)	($0.0)	$0.0	($0.0)	$0.7	3,578	370
8	Crete - St Johns Tap	Flowgate	MISO	$2.2	$2.9	$0.1	($0.7)	$0.1	$0.0	($0.0)	$0.1	($0.6)	6,756	2,240
9	5004/5005 Interface	Interface	500	($7.7)	($9.4)	($0.1)	$1.6	($0.6)	$0.5	$0.1	($1.0)	$0.6	1,810	940
10	Bedington - Black Oak	Interface	500	($2.2)	($2.7)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.0)	$0.6	1,358	14
11	Beaver - Sammis	Line	DLCO	($0.6)	($1.4)	($0.0)	$0.7	($0.1)	$0.1	$0.0	($0.2)	$0.5	442	22
12	Arsenal - Highland	Line	DLCO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.3)	$0.0	$0.4	$0.5	168	30
13	West	Interface	500	($6.8)	($7.2)	($0.1)	$0.4	($0.0)	$0.0	$0.0	($0.0)	$0.4	1,758	40
14	Burnham - Munster	Flowgate	MISO	$0.9	$1.2	$0.0	($0.4)	$0.0	$0.0	$0.0	$0.0	($0.4)	2,304	0
15	East Frankfort - Crete	Line	ComEd	$0.8	$1.2	$0.0	($0.3)	$0.0	$0.0	($0.0)	$0.0	($0.3)	3,092	658
18	Arsenal - Brunot Island	Line	DLCO	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	100	18
20	Clinton - Findlay	Line	DLCO	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.2	48	24
23	St. Joe	Other	DLCO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	878	0
24	Beaver - Clinton	Line	DLCO	$0.1	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	68	0
33	Arsenal	Transformer	DLCO	$0.1	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	34	0

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table G-43 Dominion Control Zone top congestion cost impacts (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$100.2	$82.3	$2.0	$20.0	$0.6	($1.5)	($2.9)	($0.8)	$19.2	5,172	702
2	Clover	Transformer	Dominion	$25.5	$15.2	$5.4	$15.7	($0.7)	$0.3	($7.3)	($8.3)	$7.4	3,128	904
3	Graceton - Raphael Road	Line	BGE	$53.4	$48.2	$1.3	$6.6	($0.1)	($0.9)	($1.1)	($0.2)	$6.4	5,328	1,446
4	Loudoun - Gainsville	Line	Dominion	($9.5)	($16.4)	($0.7)	$6.3	$0.5	$0.8	$0.2	($0.1)	$6.2	322	38
5	Bedington - Black Oak	Interface	500	$20.6	$17.2	$0.9	$4.3	$0.1	($0.1)	($0.5)	($0.3)	$4.1	1,560	108
6	Northwest	Other	BGE	$12.9	$10.9	$0.3	$2.3	($0.1)	($0.8)	($0.6)	$0.1	$2.4	1,168	804
7	Fredericksburg - Cranes Corner	Line	Dominion	($4.2)	($6.4)	($0.1)	$2.0	$0.4	$0.6	$0.1	($0.1)	$1.9	422	60
8	AEP - DOM	Interface	500	$20.6	$20.3	$0.6	$0.9	$0.1	($0.3)	$0.1	$0.5	$1.4	4,190	122
9	Halifax - Person	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.1	($0.4)	($1.8)	($1.4)	($1.4)	0	120
10	Crete - St Johns Tap	Flowgate	MISO	$7.4	$6.5	$0.2	$1.1	($0.0)	($0.1)	($0.0)	$0.0	$1.1	4,754	554
11	Elmont	Transformer	Dominion	$2.4	$1.5	$0.0	$1.0	$0.1	($0.1)	($0.2)	$0.0	$1.0	142	96
12	Rantoul - Rantoul Jct	Flowgate	MISO	$7.6	$6.9	$0.4	$1.0	($0.0)	($0.1)	($0.1)	($0.0)	$1.0	4,072	630
13	Valley	Transformer	Dominion	$2.4	$1.7	$0.1	$0.9	($0.2)	($0.3)	($0.1)	($0.0)	$0.9	214	22
14	Doubs - Mount Storm	Line	500	$1.3	$0.5	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	160	0
15	Beechwood - Kerr Dam	Line	Dominion	$1.6	$0.5	$0.0	$1.1	($0.1)	$0.1	($0.0)	($0.3)	$0.8	1,124	236
24	Hollymead - Charlottesville	Line	Dominion	$1.3	$0.8	$0.1	$0.7	($0.1)	($0.4)	($0.5)	($0.2)	$0.4	396	88
27	Mount Storm	Other	Dominion	$1.3	$0.9	$0.0	$0.4	$0.0	($0.0)	($0.1)	($0.0)	$0.4	106	34
29	Skimmer - Balcony Falls	Line	Dominion	$0.2	$0.1	$0.0	$0.0	($0.1)	($0.0)	($0.3)	($0.4)	($0.4)	38	66
31	Battleboro	Line	Dominion	$0.9	$0.7	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	302	18
35	Rocky Mount - Battleboro	Line	Dominion	$0.9	$0.6	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	210	0

Table G-44 Dominion Control Zone top congestion cost impacts (By facility): 2011

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$313.4	$233.9	$3.4	$82.9	($0.3)	$0.6	($4.1)	($5.0)	$77.9	8,240	2,026
2	Clover	Transformer	Dominion	$23.2	$7.9	$4.4	$19.8	($0.5)	$2.7	($8.2)	($11.4)	$8.4	2,476	938
3	AEP - DOM	Interface	500	$51.0	$46.9	$1.4	$5.6	($0.3)	($0.6)	($0.4)	($0.1)	$5.5	3,578	370
4	Danville - East Danville	Line	AEP	$60.1	$55.4	$0.7	$5.4	($0.8)	($1.5)	($0.6)	$0.0	$5.4	9,264	646
5	Bedington - Black Oak	Interface	500	$32.0	$28.6	$0.6	$4.0	$0.0	($0.0)	($0.1)	$0.0	$4.0	1,358	14
6	Valley	Transformer	Dominion	$24.7	$20.0	$1.1	$5.8	($1.3)	($0.1)	($1.3)	($2.5)	$3.3	438	196
7	Chaparral - Carson	Line	Dominion	$5.1	$4.4	$0.5	$1.2	$0.2	$1.6	($3.0)	($4.5)	($3.3)	392	360
8	Dickerson - Quince Orchard	Line	Pepco	($32.1)	($29.0)	($0.9)	($4.1)	$0.4	$1.1	$1.5	$0.8	($3.3)	284	152
9	Graceton - Raphael Road	Line	BGE	$19.1	$16.5	$0.5	$3.1	($0.2)	($0.6)	($0.6)	($0.2)	$2.9	2,324	830
10	Crete - St Johns Tap	Flowgate	MISO	$25.7	$22.9	$0.1	$2.9	($0.3)	($0.4)	($0.2)	($0.0)	$2.9	6,756	2,240
11	Mount Storm	Transformer	AP	$0.0	$0.0	$0.0	$0.0	($1.0)	($1.6)	($3.4)	($2.9)	($2.9)	0	218
12	Cloverdale - Lexington	Line	500	$12.0	$8.7	$0.9	$4.2	($0.3)	($0.6)	($2.1)	($1.7)	$2.5	1,204	854
13	Fredericksburg - Cranes Corner	Line	Dominion	($3.3)	($6.0)	($0.2)	$2.5	$0.2	$0.4	$0.2	($0.0)	$2.5	250	46
14	Wylie Ridge	Transformer	AP	$19.6	$17.6	$0.8	$2.8	$0.1	($0.1)	($0.6)	($0.3)	$2.5	3,836	760
15	Hopewell - Chesterfield	Line	Dominion	$7.8	$4.6	$0.3	$3.5	($0.3)	($1.2)	($2.0)	($1.2)	$2.3	308	126
17	Halifax - Mount Laurel	Line	Dominion	$4.7	$1.8	$0.2	$3.1	($0.4)	$0.3	($0.2)	($0.9)	$2.3	1,456	294
19	Dooms	Transformer	Dominion	$18.2	$13.6	$1.1	$5.7	($5.0)	($1.1)	($3.7)	($7.6)	($1.9)	298	236
22	Bristers - Ox	Line	Dominion	($1.7)	($3.1)	$0.0	$1.5	$0.4	$0.5	($0.1)	($0.1)	$1.4	66	50
23	Powhatan - Bremo	Line	Dominion	$2.4	$1.3	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	60	0
28	Crozet - Dooms	Line	Dominion	$3.2	$2.6	$0.2	$0.8	($0.0)	($0.0)	($0.0)	($0.0)	$0.8	236	4

Marginal Losses

Zonal Marginal Loss Costs

Table G-45 provides marginal loss costs by control zone and type for the 2012. Table G-46 provides total marginal loss costs by control zone and month for the 2011 and 2012.

Table G-45 Marginal loss costs by control zone and type (Dollars (Millions)): 2012[4]

	Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$18.6	$3.6	$0.6	$15.6	($0.0)	($0.1)	($0.5)	($0.4)	$0.0	$15.2
AEP	($154.8)	($367.7)	$0.8	$213.7	$7.0	$5.8	($9.0)	($7.8)	$0.0	$205.9
AP	($3.9)	($77.3)	$7.5	$80.9	$1.6	$6.4	($7.3)	($12.1)	$0.0	$68.7
ATSI	($3.3)	($71.9)	$2.8	$71.4	$9.0	$2.0	($3.3)	$3.7	$0.0	$75.1
BGE	$88.5	$47.1	$8.9	$50.3	$1.7	($0.6)	($7.6)	($5.3)	$0.0	$45.0
ComEd	($303.7)	($483.2)	($2.2)	$177.2	$8.1	$2.0	$1.6	$7.7	$0.0	$184.9
DAY	($4.6)	($45.7)	($1.7)	$39.4	($1.4)	$2.1	($1.1)	($4.6)	$0.0	$34.8
DEOK	($48.2)	($54.4)	($3.7)	$2.5	$2.4	$1.4	($0.3)	$0.7	$0.0	$3.2
DLCO	($17.2)	($29.2)	$0.4	$12.4	($0.4)	$0.0	($0.4)	($0.9)	$0.0	$11.5
Dominion	$80.2	($6.8)	$8.7	$95.7	$4.9	$3.7	($6.8)	($5.6)	$0.0	$90.1
DPL	$48.5	$11.0	$4.9	$42.4	($2.3)	$0.3	($3.9)	($6.5)	$0.0	$35.9
External	($26.6)	($40.1)	($61.3)	($47.8)	($2.6)	($5.1)	$23.3	$25.8	$0.0	($22.0)
JCPL	$35.8	$12.9	($0.2)	$22.8	$0.3	$0.4	($1.0)	($1.1)	$0.0	$21.7
Met-Ed	$11.5	($2.3)	$0.1	$13.9	$0.4	$0.1	$0.2	$0.5	$0.0	$14.4
PECO	$55.8	$26.2	$0.6	$30.2	$0.0	$0.0	($0.5)	($0.5)	$0.0	$29.6
PENELEC	($1.1)	($45.9)	$2.2	$47.0	$1.6	$0.1	($2.5)	($1.0)	$0.0	$46.0
Pepco	$75.8	$39.0	$6.6	$43.4	($1.1)	($0.2)	($5.5)	($6.4)	$0.0	$37.0
PPL	$23.5	($10.7)	($3.4)	$30.8	$1.9	$0.9	$1.9	$2.9	$0.0	$33.7
PSEG	$80.0	$35.0	$15.0	$60.0	$1.0	$4.3	($7.9)	($11.3)	$0.0	$48.7
RECO	$2.1	$0.0	$0.1	$2.2	$0.0	($0.0)	($0.1)	($0.1)	$0.0	$2.1
Total	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7

4 The "External" zone was labeled as "PJM" in previous State of the Market reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM external interfaces.

Table G-46 Monthly marginal loss costs by control zone (Dollars (Millions)): 2011 and 2012

Marginal Loss Costs by Control Zone (Millions)														
2011														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$2.9	$2.0	$1.8	$1.5	$1.5	$3.2	$6.0	$3.2	$1.9	$0.8	$0.8	$0.3	$0.0	$26.0
AEP	$42.3	$25.8	$24.0	$19.4	$18.3	$30.6	$54.9	$34.5	$24.6	$15.4	$15.9	$12.9	$0.0	$318.6
AP	$14.3	$8.4	$7.7	$6.5	$6.6	$9.1	$16.1	$10.1	$7.4	$5.3	$5.3	$5.3	$0.0	$102.0
ATSI	NA	NA	NA	NA	NA	$1.5	$2.7	$2.2	$1.7	$5.2	$2.8	$3.2	$0.0	$19.3
BGE	$6.5	$5.0	$3.9	$3.2	$3.8	$6.3	$11.7	$6.6	$4.8	$3.3	$3.5	$2.9	$0.0	$61.3
ComEd	$32.3	$21.9	$23.1	$17.8	$15.3	$22.7	$30.1	$21.0	$21.1	$18.0	$18.6	$17.3	$0.0	$259.2
DAY	$5.2	$5.0	$4.5	$2.8	$4.1	$5.9	$10.3	$7.0	$6.7	$5.6	$4.8	$4.2	$0.0	$66.1
DEOK	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	$0.0	$0.0
DLCO	$2.2	$1.6	$0.7	$0.8	$1.2	$1.2	$1.3	$1.1	$1.2	$1.3	$1.1	$0.9	$0.0	$14.6
Dominion	$19.8	$11.6	$9.7	$4.3	$8.2	$8.3	$24.0	$14.6	$10.2	$6.5	$6.0	$5.5	$0.0	$128.7
DPL	$7.7	$5.3	$3.6	$2.7	$2.6	$4.7	$7.9	$5.5	$3.8	$1.9	$1.7	$1.0	$0.0	$48.5
EXT	$6.4	$4.1	$0.0	($0.7)	($0.1)	($2.5)	($6.9)	($7.2)	($7.4)	($3.6)	($6.5)	($2.6)	$0.0	($26.9)
JCPL	$6.2	$4.1	$3.1	$2.5	$2.3	$3.6	$6.6	$3.3	$2.7	$1.4	$0.7	$1.3	$0.0	$37.9
Met-Ed	$2.1	$1.4	$1.4	$1.2	$1.5	$1.6	$2.4	$1.8	$1.4	$1.4	$1.5	$1.6	$0.0	$19.1
PECO	$6.6	$3.5	$3.5	$3.7	$4.9	$6.3	$10.0	$5.7	$3.7	$3.8	$3.7	$3.9	$0.0	$59.2
PENELEC	$8.9	$5.3	$3.6	$3.1	$5.0	$6.9	$10.3	$7.2	$4.7	$3.4	$3.2	$1.9	$0.0	$63.5
Pepco	$5.9	$3.7	$3.9	$3.1	$3.7	$5.1	$8.2	$5.2	$4.1	$2.8	$2.5	$2.3	$0.0	$50.5
PPL	$8.6	$4.7	$3.0	$2.6	$3.1	$4.4	$7.9	$6.1	$3.9	$4.2	$4.4	$4.0	$0.0	$56.9
PSEG	$7.3	$6.1	$6.3	$4.6	$5.2	$6.4	$9.7	$6.2	$6.0	$5.5	$4.0	$4.5	$0.0	$71.8
RECO	$0.5	$0.3	$0.3	$0.2	$0.2	$0.3	$0.5	$0.3	$0.3	$0.2	$0.1	$0.1	$0.0	$3.2
Total	$185.7	$119.9	$104.0	$79.2	$87.3	$125.4	$213.7	$134.5	$102.9	$82.0	$74.3	$70.6	$0.0	$1,379.6
Marginal Loss Costs by Control Zone (Millions)														
2012														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charges	Grand Total
AECO	$0.9	$0.7	$0.7	$0.4	$0.7	$1.4	$3.1	$2.5	$1.2	$1.0	$1.5	$1.2	$0.0	$15.2
AEP	$22.0	$17.4	$11.8	$13.2	$14.1	$19.2	$31.7	$21.7	$13.9	$14.9	$14.7	$11.5	$0.0	$205.9
AP	$5.4	$5.4	$4.0	$3.2	$3.9	$6.7	$8.3	$6.7	$5.9	$5.0	$7.7	$6.6	$0.0	$68.7
ATSI	$5.8	$5.9	$5.1	$4.4	$6.8	$7.4	$11.5	$6.5	$4.6	$5.1	$5.4	$6.7	$0.0	$75.1
BGE	$4.2	$4.1	$3.2	$2.4	$2.4	$4.3	$6.3	$4.5	$3.2	$2.9	$4.1	$3.5	$0.0	$45.0
ComEd	$17.9	$13.8	$11.5	$11.2	$12.4	$15.6	$21.4	$16.0	$13.9	$14.7	$19.5	$16.9	$0.0	$184.9
DAY	$3.4	$2.4	$2.6	$1.7	$2.8	$3.7	$5.1	$2.4	$3.4	$2.4	$1.7	$3.3	$0.0	$34.8
DEOK	$0.0	$0.6	($0.9)	($0.3)	$0.5	$0.0	$0.8	$2.0	($0.4)	$0.6	$0.2	$0.1	$0.0	$3.2
DLCO	$1.0	$1.2	$1.1	$0.4	$0.8	$1.1	$1.2	$1.0	$0.7	$0.3	$1.3	$1.4	$0.0	$11.5
Dominion	$8.0	$6.7	$5.7	$4.7	$6.0	$9.2	$14.8	$9.6	$7.0	$5.7	$7.4	$5.3	$0.0	$90.1
DPL	$3.5	$2.9	$2.1	$1.6	$1.9	$3.2	$6.2	$4.2	$2.5	$1.9	$3.2	$2.7	$0.0	$35.9
EXT	($0.5)	($1.6)	($0.4)	($3.6)	($1.6)	($0.9)	($2.3)	($0.3)	($2.1)	($5.1)	($2.5)	($1.1)	$0.0	($22.0)
JCPL	$1.9	$1.4	$1.1	$1.0	$1.2	$2.2	$3.6	$2.3	$1.2	$1.4	$2.1	$2.4	$0.0	$21.7
Met-Ed	$1.3	$1.2	$1.0	$0.9	$0.8	$1.3	$2.2	$1.2	$1.1	$1.1	$1.1	$1.2	$0.0	$14.4
PECO	$3.5	$2.7	$2.2	$1.7	$2.9	$3.2	$6.2	$2.4	$2.1	$1.8	$0.5	$0.7	$0.0	$29.6
PENELEC	$4.8	$2.6	$3.3	$1.7	$4.1	$4.6	$7.6	$4.2	$3.1	$2.5	$3.7	$3.8	$0.0	$46.0
Pepco	$4.0	$4.1	$2.9	$2.0	$2.0	$3.2	$4.2	$3.4	$2.9	$2.8	$2.8	$2.7	$0.0	$37.0
PPL	$3.8	$2.4	$2.3	$1.7	$2.1	$2.4	$5.4	$3.7	$3.2	$2.5	$2.9	$1.3	$0.0	$33.7
PSEG	$4.1	$3.3	$2.6	$2.5	$3.4	$4.4	$6.0	$4.2	$3.3	$3.0	$5.1	$6.9	$0.0	$48.7
RECO	$0.2	$0.1	$0.1	$0.1	$0.1	$0.2	$0.3	$0.3	$0.1	$0.1	$0.2	$0.2	$0.0	$2.1
Total	$95.2	$77.2	$61.9	$51.0	$67.1	$92.5	$143.4	$98.5	$70.8	$64.1	$82.5	$77.5	$0.0	$981.7

Energy

Zonal Energy Costs

Table G-47 provides energy costs by control zone and type for the 2012. Table G-48 provides total energy costs by control zone and month for the 2011 and 2012.

Table G-47 Energy costs by control zone and type (Dollars (Millions)): 2012

Energy Costs by Control Zone (Millions)										
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
AECO	$400.6	$114.3	$0.0	$286.2	$2.2	($2.7)	$0.0	$4.9	$0.1	$291.3
AEP	$5,281.2	$5,870.0	$0.0	($588.8)	($109.6)	($70.1)	$0.0	($39.5)	$1.6	($626.7)
AP	$1,752.4	$2,080.3	$0.0	($327.8)	($5.4)	($168.5)	$0.0	$163.1	$0.5	($164.1)
ATSI	$2,546.8	$2,301.4	$0.0	$245.4	($16.2)	($84.0)	$0.0	$67.8	$0.8	$314.0
BGE	$1,927.2	$1,576.3	$0.0	$350.9	$37.0	($17.4)	$0.0	$54.4	$0.4	$405.7
ComEd	$5,126.8	$5,816.2	$0.0	($689.3)	($85.6)	($53.6)	$0.0	($32.0)	$1.2	($720.2)
DAY	$671.5	$655.9	$0.0	$15.6	$11.5	($28.4)	$0.0	$39.9	$0.2	$55.7
DEOK	$932.9	$723.2	$0.0	$209.7	$0.8	($26.9)	$0.0	$27.7	$0.3	$237.7
DLCO	$548.3	$622.0	$0.0	($73.8)	$13.2	($3.2)	$0.0	$16.4	$1.1	($56.3)
Dominion	$6,302.1	$6,036.5	$0.0	$265.6	($53.0)	($214.4)	$0.0	$161.4	$0.2	$427.2
DPL	$705.9	$321.8	$0.0	$384.1	$9.5	$67.1	$0.0	($57.6)	$0.2	$326.7
External	$591.9	$766.6	$0.0	($174.7)	$141.6	$267.1	$0.0	($125.5)	$0.0	($300.2)
JCPL	$858.2	$492.3	$0.0	$365.9	($8.4)	$5.3	$0.0	($13.8)	$0.3	$352.5
Met-Ed	$659.8	$849.2	$0.0	($189.4)	($4.9)	($7.8)	$0.0	$2.9	$0.2	($186.3)
PECO	$1,879.2	$2,549.4	$0.0	($670.2)	($13.1)	$14.6	$0.0	($27.7)	$0.5	($697.3)
PENELEC	$1,778.8	$2,254.7	$0.0	($475.9)	($78.5)	$20.1	$0.0	($98.6)	$0.2	($574.3)
Pepco	$2,106.8	$1,456.8	$0.0	$650.0	($55.1)	$0.5	$0.0	($55.6)	$0.4	$594.8
PPL	$1,774.7	$2,088.5	$0.0	($313.9)	$33.5	$14.5	$0.0	$19.0	$0.5	($294.4)
PSEG	$1,741.1	$1,674.7	$0.0	$66.3	$11.2	$110.3	$0.0	($99.1)	$0.5	($32.3)
RECO	$55.1	$1.1	$0.0	$54.0	($0.6)	($0.4)	$0.0	($0.2)	$0.0	$53.8
Total	$37,641.2	$38,251.1	$0.0	($609.9)	($169.8)	($177.6)	$0.0	$7.8	$9.1	($593.0)

Table G-48 Monthly energy costs by control zone (Dollars (Millions)): 2011 and 2012

Energy Costs by Control Zone (Millions) 2011														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$37.4	$27.3	$28.1	$25.4	$28.3	$39.9	$61.3	$39.1	$30.1	$24.5	$22.4	$25.4	$0.4	$389.4
AEP	($86.5)	($56.4)	($67.0)	($71.3)	($29.3)	($130.4)	($199.5)	($126.9)	($74.5)	($22.6)	$1.0	($27.6)	$5.2	($885.8)
AP	$6.8	$7.8	$11.2	($10.8)	($5.4)	($37.4)	($38.2)	($29.7)	($20.6)	($11.6)	($14.2)	($13.9)	$1.8	($154.0)
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$49.9	$37.5	$16.1	$12.8	$44.6	$29.8	$32.6	$1.6	$224.8
BGE	$42.8	$52.6	$35.4	$21.6	$26.0	$49.9	$80.2	$47.2	$33.9	$28.5	$26.8	$29.3	$1.3	$475.5
ComEd	($123.9)	($87.6)	($96.8)	($78.9)	($52.4)	($89.3)	($36.7)	($51.3)	($94.6)	($94.6)	($95.8)	($99.0)	$3.9	($997.2)
DAY	$0.3	($14.8)	($9.9)	$0.7	($12.5)	($11.3)	($20.3)	($12.9)	($30.7)	($33.7)	($24.8)	($24.0)	$0.7	($193.2)
DEOK	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
DLCO	($13.9)	($14.2)	$10.9	($6.2)	($17.8)	($12.3)	($0.8)	($3.2)	($13.4)	($11.6)	($13.8)	($4.5)	$3.7	($97.1)
Dominion	$80.2	$49.6	$36.0	$53.0	$66.3	$73.7	$46.4	$55.7	$65.5	$82.3	$73.8	$38.3	$0.7	$721.6
DPL	$82.2	$51.3	$40.5	$28.3	$34.7	$45.6	$62.8	$45.9	$37.0	$29.6	$25.9	$33.3	$0.6	$517.7
External	($38.7)	($2.2)	$16.3	$25.3	($0.3)	($10.0)	($47.8)	$35.4	$52.8	$16.5	$13.7	$33.1	$0.0	$94.1
JCPL	$72.7	$44.5	$37.4	$26.1	$36.6	$55.0	$89.9	$52.6	$34.4	$18.6	$17.5	$28.2	$0.9	$514.5
Met-Ed	($23.1)	($16.6)	($16.6)	($30.3)	($20.2)	($27.9)	($37.5)	($28.0)	($20.5)	($16.9)	($4.3)	($16.5)	$0.6	($257.8)
PECO	($51.3)	($55.0)	($71.3)	($45.1)	($93.1)	($65.5)	($64.9)	($65.2)	($47.1)	($51.8)	($66.9)	($62.8)	$1.6	($738.3)
PENELEC	($110.0)	($67.2)	($39.7)	($44.9)	($70.4)	($104.8)	($107.4)	($89.0)	($50.6)	($28.0)	($41.0)	($30.7)	$0.7	($783.0)
Pepco	$80.2	$58.5	$57.2	$61.9	$58.8	$76.3	$84.2	$79.5	$66.4	$50.4	$46.0	$63.8	$1.2	$784.4
PPL	($35.7)	($29.2)	($27.6)	($14.6)	($6.1)	($4.1)	($78.8)	($65.0)	($60.0)	($71.8)	($49.0)	($47.6)	$1.6	($487.9)
PSEG	($22.2)	($16.8)	($6.8)	$4.8	($4.8)	$9.5	$31.3	$9.7	$13.4	($5.0)	$4.7	($11.9)	$1.7	$7.6
RECO	$7.2	$4.9	$4.8	$4.7	$6.3	$8.0	$11.4	$6.9	$5.2	$3.9	$3.6	$3.9	$0.1	$70.7
Total	($95.5)	($63.5)	($57.8)	($50.2)	($55.0)	($85.4)	($126.8)	($83.2)	($60.5)	($48.6)	($44.8)	($50.7)	$28.3	($793.8)

Energy Costs by Control Zone (Millions) 2012														
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Inadvertent Charge	Grand Total
AECO	$24.7	$21.1	$18.6	$16.6	$21.0	$26.6	$41.1	$32.9	$23.3	$21.3	$20.4	$23.4	$0.1	$291.3
AEP	($54.7)	($38.6)	($8.6)	($49.9)	($27.7)	($45.2)	($94.2)	($86.6)	($46.8)	($65.2)	($50.4)	($60.3)	$1.6	($626.7)
AP	$25.9	$3.2	($3.4)	$12.9	($5.0)	($28.2)	($19.8)	($30.1)	($30.5)	($19.5)	($42.5)	($27.6)	$0.5	($164.1)
ATSI	$33.8	$23.0	$16.0	($0.4)	$11.1	$18.9	$13.5	$29.3	$56.5	$40.5	$47.4	$23.7	$0.8	$314.0
BGE	$40.5	$49.1	$42.0	$20.5	$16.5	$31.9	$53.9	$42.1	$25.6	$21.1	$31.8	$30.3	$0.4	$405.7
ComEd	($101.7)	($76.6)	($59.7)	($64.4)	($63.7)	($39.9)	($8.5)	($33.7)	($56.3)	($67.5)	($80.9)	($68.4)	$1.2	($720.2)
DAY	$3.6	$7.5	$0.6	$8.6	$13.7	$4.8	$0.2	($0.5)	($5.7)	$9.1	$16.9	($3.2)	$0.2	$55.7
DEOK	$12.6	$4.7	$34.4	$23.2	$29.6	$32.4	$37.5	$6.7	$26.2	$16.3	$4.4	$9.4	$0.3	$237.7
DLCO	($6.7)	($14.1)	($11.6)	$7.6	$5.1	($4.3)	$1.2	($6.0)	($7.5)	$8.5	($13.2)	($16.4)	$1.1	($56.3)
Dominion	$30.1	$12.7	$17.3	$56.1	$47.2	$8.6	$13.1	$37.0	$31.4	$58.8	$70.1	$44.6	$0.2	$427.2
DPL	$36.3	$27.9	$22.1	$14.4	$17.8	$25.6	$38.4	$32.3	$21.7	$21.3	$37.6	$31.0	$0.2	$326.7
External	($12.3)	($15.3)	($27.9)	($11.0)	($32.5)	($49.0)	($58.3)	($19.2)	($7.3)	($17.7)	($54.9)	$5.1	$0.0	($300.2)
JCPL	$35.0	$25.3	$18.7	$10.1	$18.5	$31.1	$58.5	$36.1	$19.8	$24.2	$39.8	$35.2	$0.3	$352.5
Met-Ed	($10.9)	($21.8)	($14.0)	($19.6)	($0.1)	($15.8)	($26.1)	($7.5)	($21.0)	($23.3)	($16.8)	($9.7)	$0.2	($186.3)
PECO	($76.7)	($64.4)	($45.6)	($63.7)	($63.9)	($56.7)	($42.7)	($49.7)	($32.4)	($44.3)	($83.1)	($74.7)	$0.5	($697.3)
PENELEC	($62.2)	($18.8)	($46.0)	($18.2)	($56.9)	($55.4)	($96.2)	($56.7)	($38.8)	($35.0)	($43.7)	($46.6)	$0.2	($574.3)
Pepco	$67.9	$60.7	$49.7	$29.1	$39.5	$57.9	$63.1	$59.2	$48.1	$36.1	$29.0	$54.2	$0.4	$594.8
PPL	($39.1)	($21.9)	($31.4)	($5.9)	($9.0)	$0.6	($66.4)	($53.7)	($41.1)	($22.3)	$7.3	($11.9)	$0.5	($294.4)
PSEG	($8.6)	($13.1)	($13.3)	($2.6)	($4.7)	($2.2)	$2.5	$4.7	($12.1)	($6.8)	$19.3	$4.0	$0.5	($32.3)
RECO	$4.1	$3.4	$3.3	$3.1	$4.1	$5.2	$8.3	$5.9	$4.3	$3.8	$4.2	$4.1	$0.0	$53.8
Total	($58.6)	($45.9)	($38.7)	($33.5)	($39.3)	($53.1)	($81.0)	($57.7)	($42.6)	($40.6)	($57.3)	($53.7)	$9.1	($593.0)

FTR Volumes

This Appendix presents the data used to create Figure 8-1 in the *2012 State of the Market Report for PJM*. Each table shows the FTR bid volume, cleared volume and net bid volume by planning period. The bid volume includes the buy, sell and self-scheduled offers. The cleared volume includes the buy, sell and self-scheduled offers that clear. The net bid volume includes all bid and self-scheduled offers, excluding sell offers. The Annual Auction volume is included in June of each planning period.

Table H-1 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2003 to 2004

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-03	2,679,072	89,840	2,690,737
Jul-03	295,753	8,642	300,808
Aug-03	215,206	9,978	220,241
Sep-03	226,994	9,068	234,315
Oct-03	127,739	10,522	135,885
Nov-03	114,211	8,247	122,362
Dec-03	131,180	8,352	139,221
Jan-04	128,086	10,947	136,657
Feb-04	128,303	12,187	137,790
Mar-04	144,617	13,827	156,543
Apr-04	141,437	17,358	157,776
May-04	168,480	44,641	178,973
Total	4,501,077	243,608	4,611,308

Table H-2 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2004 to 2005

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-04	939,214	125,044	1,019,868
Jul-04	160,472	21,761	190,198
Aug-04	144,402	22,650	176,642
Sep-04	155,837	13,999	194,229
Oct-04	180,542	49,816	226,156
Nov-04	213,036	23,912	247,780
Dec-04	226,271	18,384	260,964
Jan-05	212,061	22,549	236,135
Feb-05	276,385	20,700	305,613
Mar-05	306,472	25,712	348,416
Apr-05	307,297	36,914	330,088
May-05	280,690	32,545	300,966
Total	3,402,681	413,987	3,837,056

Table H-3 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2005 to 2006

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-05	1,011,821	159,049	1,120,404
Jul-05	300,153	23,929	340,891
Aug-05	233,493	17,966	276,936
Sep-05	222,404	22,133	266,577
Oct-05	147,493	18,906	189,458
Nov-05	183,750	20,525	227,432
Dec-05	200,886	19,422	244,608
Jan-06	234,473	21,431	275,081
Feb-06	250,308	26,463	293,774
Mar-06	272,662	31,968	317,705
Apr-06	431,398	36,603	472,732
May-06	384,767	38,977	424,962
Total	3,873,608	437,372	4,450,561

Table H-4 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2006 to 2007

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-06	2,274,846	198,380	2,533,660
Jul-06	719,494	31,662	934,424
Aug-06	738,375	26,392	932,469
Sep-06	630,072	37,351	841,698
Oct-06	710,045	51,193	888,011
Nov-06	765,177	40,110	890,318
Dec-06	757,683	42,848	919,549
Jan-07	778,266	59,813	905,249
Feb-07	884,953	68,179	969,447
Mar-07	661,938	69,754	799,130
Apr-07	455,411	30,963	551,601
May-07	432,783	37,207	480,219
Total	9,809,046	693,852	11,645,776

Table H-5 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2007 to 2008

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-07	2,961,754	323,632	3,462,015
Jul-07	794,490	51,248	1,068,961
Aug-07	944,015	63,392	1,224,668
Sep-07	901,284	66,611	1,200,730
Oct-07	973,936	112,427	1,245,797
Nov-07	841,326	61,592	1,059,631
Dec-07	1,276,687	49,825	1,461,068
Jan-08	501,642	27,377	655,581
Feb-08	583,749	37,288	676,847
Mar-08	437,241	31,941	590,524
Apr-08	326,050	34,805	427,105
May-08	280,005	22,837	331,327
Total	10,822,178	882,975	13,404,256

Table H-6 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2008 to 2009

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-08	3,511,130	339,654	3,832,169
Jul-08	968,615	53,843	1,211,784
Aug-08	961,694	40,027	1,224,054
Sep-08	925,250	64,901	1,127,274
Oct-08	802,966	52,768	965,756
Nov-08	607,441	45,707	738,336
Dec-08	550,352	37,633	748,485
Jan-09	488,102	43,739	673,525
Feb-09	492,216	40,439	639,274
Mar-09	391,938	42,722	581,075
Apr-09	299,908	35,685	440,629
May-09	222,092	21,016	295,198
Total	10,221,706	818,134	12,477,560

Table H-7 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2009 to 2010

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-09	2,652,340	307,584	3,156,826
Jul-09	488,748	41,389	849,742
Aug-09	414,151	55,261	708,452
Sep-09	427,221	56,998	718,246
Oct-09	538,476	64,328	797,069
Nov-09	559,750	65,577	745,333
Dec-09	447,221	68,470	672,986
Jan-10	529,887	64,435	728,765
Feb-10	490,391	62,153	670,272
Mar-10	389,934	73,069	615,690
Apr-10	345,301	66,017	489,638
May-10	291,537	52,036	375,812
Total	7,574,956	977,318	10,528,830

Table H-8 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2010 to 2011

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-10	3,177,131	428,603	3,894,566
Jul-10	720,172	102,883	1,145,991
Aug-10	859,260	93,226	1,202,137
Sep-10	1,079,947	144,423	1,510,812
Oct-10	1,041,425	120,281	1,427,494
Nov-10	922,444	111,442	1,261,969
Dec-10	1,005,436	157,609	1,359,582
Jan-11	902,052	132,866	1,207,101
Feb-11	931,164	160,750	1,184,383
Mar-11	952,963	182,340	1,250,283
Apr-11	660,480	138,230	913,583
May-11	620,691	169,610	762,538
Total	12,873,166	1,942,261	17,120,443

Table H-9 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2011 to 2012

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-11	6,233,773	847,183	7,437,352
Jul-11	1,602,795	241,288	2,233,307
Aug-11	1,385,040	204,442	1,981,888
Sep-11	969,184	112,746	1,581,241
Oct-11	1,424,062	134,653	1,908,956
Nov-11	1,098,133	117,705	1,562,764
Dec-11	811,035	93,492	1,318,347
Jan-12	772,843	88,683	1,240,355
Feb-12	816,356	93,977	1,234,341
Mar-12	665,949	99,659	1,126,207
Apr-12	449,078	131,218	795,785
May-12	295,103	94,642	470,495
Total	16,523,352	2,259,688	22,891,036

Table H-10 Annual and Monthly FTR Auction bid and cleared volume: Planning period 2012 to 2013

Auction Date	Net Bid Volume (MW)	Cleared Volume (MW)	Bid Volume (MW)
Jun-12	6,407,647	710,169	7,598,008
Jul-12	2,177,990	182,695	2,735,269
Aug-12	909,111	151,693	1,418,249
Sep-12	1,877,747	146,352	2,446,553
Oct-12	788,486	118,052	1,310,859
Nov-12	1,765,875	98,494	2,142,231
Dec-12	1,757,292	115,322	2,230,391
Total	15,684,148	1,522,778	19,881,561

Glossary

Aggregate
Combination of buses or bus prices.

Ancillary Services
Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Area Control Error (ACE)
Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.

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.

Avoidable cost rate (ACR)
The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.

Avoidable Project Investment Recovery Rate (APIR)
A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market
Energy that is generated and financially settled during real time.

Base Residual Auction (BRA)
Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

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 any outside assistance from the transmission system or interconnection.

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 deficiency rate (CDR)
The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.

Capacity Emergency Transfer Limit (CETL)
The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

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)
An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.

Combustion Turbine (CT)
A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.

Congestion Management Process (CMP)
A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.

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)
An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).

Demand deviations
Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.

Demand Resource
A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.

Dispatch Rate
The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.

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.

Eastern Region
Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.

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 proportion of hours in a year that a unit is available to generate at full capacity.

Equivalent demand forced outage rate (EFORd)
A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.

Equivalent forced outage factor (EFOF)
The proportion of hours in a year that a unit is unavailable because of forced outages.

Equivalent maintenance outage factor (EMOF)
The proportion of hours in a year that a unit is unavailable because of maintenance outages.

Equivalent planned outage factor (EPOF)
The proportion of hours in a year that a unit is unavailable because of planned outages.

External resource
A generation resource located outside metered boundaries of the PJM RTO.

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 Service
Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.

Firm Transmission Service
Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid
Bid to purchase a defined MW level of energy, regardless of LMP.

Fixed Resource Requirement (FRR)
An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flowgate
A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.

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 Control Area (GCA) and Load Control Area (LCA)
Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms "Control Area" in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.

Generator deviations
Hourly deviations in the generator category, equal to the difference between a unit's cleared day-ahead generation, and a unit's hourly, integrated real-time generation.

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 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.

Increment offers (INC)
Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.

Incremental Auction
Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.

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 Management
Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).

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.

Locational Deliverability Area (LDA)
Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit
The last, highest cost, 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.

Maximum daily starts
The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.

Maximum weekly starts
The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.

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.

Minimum down time
The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.

Minimum run time
The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.

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.

Network Transmission Service
Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.

Noneconomic generation
Units producing energy at an offer price greater than the LMP.

Non-Firm Transmission Service
Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

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.

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.

Opportunity cost
In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule
A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.

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.

Point of Receipt (POR) and Point of Delivery (POD)

Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.

Pool-scheduled resource

A generating resource that the seller has turned over to PJM for scheduling and control.

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.

Ramp-limited desired (MW)

The achievable MW based on the UDS requested ramp rate.

Regional Transmission Expansion Planning (RTEP) 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).

Reliability Pricing Model (RPM)

PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

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.

Short-Term Resource Procurement Target

The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.

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 Import Transmission Service

Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.

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.

Summer Net Capability

The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load.

Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available.

For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday.

For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability.

For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations

Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.

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) if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)

Transmission Adequacy and Reliability Assessment (TARA)

An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.

Turn down ratio

The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.

Unforced capacity

Installed capacity adjusted by forced outage rates.

Western region

Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through

An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.

Winter Weather Parameter (WWP)

WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)

Zone

See "Control zone" (above).

List of Acronyms

AC2	Advanced Control Center
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
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMI	Advanced Metering Infrastructure
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ASO	Ancillary Service Optimization
ATC	Available transfer capability
ATSI	American Transmission Systems, Inc.
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BACT	Best Available Control Technology
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BOR	Balancing Operating Reserve
BRA	Base Residual Auction
BSSWG	Black Start Services Working Group
BTU	British thermal unit
C&I	Commercial and industrial customers
CAAA	Clean Air Act Amendments
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDS	Cost Development Subcommittee
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

CIDS	Critical Infrastructure Protocol
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPI	Consumer Price Index
CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CRF	Capital Recovery Factor
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLC	Direct Load Control
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DRS	Demand Response Subcommittee
DRSDTF	Demand Response Subzonal Dispatch Task Force
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EFORp	Equivalent forced outage rate during peak hours
EHV	Extra-high-voltage
EIS	Environmental Information Services
EKPC	East Kentucky Power Cooperative, Inc.
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPA	Environmental Protection Agency

EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
ESP	Electrostatic Precipitators (Baghouses)
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FGD	Flue-gas desulfurization
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FSL	Firm Service Load
FTR	Financial Transmission Right
FTRTF	Financial Transmission Rights Task Force
GACT	Generally Available Control Technology
GCA	Generation control area
GE	General Electric Company
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GW	Gigawatt
GWh	Gigawatt-hour
HAP	Hazardous Air Pollutants
HE	Hour Ending
HEDD	NJ High Energy Demand Day
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IARR	Incremental ARRs
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
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
ITSCED	Intermediate Term Security Constrained Economic Dispatch
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units

JRCA	Joint Reliability Coordination Agreement
KV	KiloVolt
KDAEV	Known Day-Ahead Error Value
LAER	Lowest Achievable Emissions Rate
LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LMTF	Load Management Task Force
LOC	Lost opportunity cost
LPC	Locational Pricing Calculator
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
MACT	Maximum Achievable Control Technology
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MATS	Mercury and Air Toxics Standards rule
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MIC	Market Implementation Committee
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NBT	Net Benefits Test
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line

NERC	North American Electric Reliability Council
NESHAP	National Emission Standards for Hazardous Air Pollutants
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NNL	Network and native load
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
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
OPSI	Organization of PJM States, Inc.
OMC	Outside Management Control
OVEC	Ohio Valley Electric Corporation
ORS	NERC Operating Reliability Subcommittee
PAR	Phase angle regulator
PATH	Potomac – Appalachian Transmission Highline
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PHI	Pepco Holdings, Inc.
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/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
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/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
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
PLC	Peak Load Contribution
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPB	Parts per billion
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSD	Prevention of Significant Deterioration
PSN	PSEG north
PSNC	PSEG north central
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCF	Reciprocal Coordinated Flowgate
RCIS	Reliability Coordinator Information System
REC	Renewable Energy Credit
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCCP	Regulation market capability clearing price
RMCP	Regulation market-clearing price
RMPCP	Regulation market performance clearing price
RMR	Reliability Must Run
ROFR	Right of First Refusal
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RRMSE	Relative Root Mean Squared Error
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
SAA	Symmetrical Additive Adjustment
SCE&G	South Carolina Energy and Gas
SCED	Security Constrained Economic Dispatch
SCPA	South central Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea

SERC	SERC Reliability Corporation
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNCR	Selective Non-Catalytic Reduction
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
STRPTAS	Short Term Resource Procurement Applicable Share
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TISTF	Transactions Issues Senior Task Force
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TPY	Tons Per Year
TrAIL	Trans – Allegheny Interstate Line
TSIN	NERC Transmission System Information Network
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
VFT	Variable frequency transformer
VOCs	Volatile Organic Compounds
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion
WWP	Winter Weather Parameter
XEFORd	EFORd modified to exclude OMC outages