Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at any bus is made up of three components: the system marginal price or energy component (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 congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Congestion is neither good nor bad but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses. The Market Monitoring Unit (MMU) analyzed marginal losses and congestion in PJM markets for the first six months of 2012.[2]

1 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.

2 The total marginal loss and congestion results were calculated as of July 20, 2012, and are subject to change, based on continued PJM billing updates.

Highlights

- Total marginal loss costs decreased by $256.7 million or 36.6 percent, from $701.5 million in the first six months of 2011 to $444.8 million in the first six months of 2012 (Table 10-10).
- Day-ahead marginal loss costs decreased by $261.7 million or 35.9 percent, from $728.1 million in the first six months of 2011 to $466.4 million in the first six months of 2012 (Table 10-12).
- Balancing marginal loss costs increased by -$5.0 million or 18.9 percent, from -$26.6 million in the first six months of 2011 to -$21.6 million in the first six months of 2012 (Table 10-12).
- The marginal loss credits (loss surplus) decreased by $126.3 million or 41.0 percent, from $308.4 million in the first six months of 2011 to $182.1 million in the first six months of 2012. (Table 10-13).
- Total congestion decreased by $306.8 million or 53.8 percent, from $570 million in the first six months of 2011 to $263.2 million in the first six months of 2012 (Table 10-15).
- Day-ahead congestion costs decreased by $312.3 million or 44.5 percent, from $701.9 million in the first six months of 2011 to $389.6 million in the first six months of 2012.
- Balancing congestion costs decreased by $5.5 million or 4.4 percent, from -$126.4 million in the first six months of 2011 to -$131.9 million in the first six months of 2012.

Conclusion

Marginal losses reflect the incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. Total marginal loss costs decreased by $256.7 million or 36.6 percent, from $701.5 million in the first six months of 2011 to $444.8 million in the first six months of 2012.

Marginal loss credits are distributed to load and exports. Marginal loss credits were $182.1 million in the first six months of 2012.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load. Total congestion costs decreased by $306.8 million or 53.8 percent, from $570.0 million in the first six months of 2011 to $263.2 million in the first six months of 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 97.3 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2010 to 2011 planning period.[3] In the 2011 to 2012 planning period, total ARR and FTR revenues offset 88.8 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 92.9 percent of the target allocation level for the first month of the 2012 to 2013 planning period.[4] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[5] 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 total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total 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 total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. 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).

As an example, total congestion costs in PJM in the first six months of 2012 were $263.2 million, which was comprised of load congestion payments of $60.5 million, negative generation credits of $239.1 million and negative explicit congestion of $36.4 million (Table 10-15).

3 See the *2012 Quarterly State of the Market Report for PJM: January through June*, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-29, "ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012.

4 See the *2012 Quarterly State of the Market Report for PJM: January through June*, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-16, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

5 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first six months for years 2009 to 2012.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2009 through 2012 (See 2011 SOM, Table 10-1)

(Jan-Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first six months of 2009 through 2012.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2009 through 2012 (See 2011 SOM, Table 10-2)

(Jan-Jun)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	$0.00
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.83	$31.76	$0.10	($0.02)

Zonal Components

The components of LMP were calculated for each PJM control zone. The real time components of LMP for the control zones are presented in Table 10-3 for January through June of years 2011 and 2012. The day-ahead components of LMP for the control zones are presented in Table 10-4 for January through June of years 2011 and 2012.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2011 and 2012 (See 2011 SOM, Table 10-3)

	2011 (Jan-Jun)				2012 (Jan-Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.67	$48.74	$4.51	$2.42	$31.72	$31.37	($0.59)	$0.94
AEP	$41.82	$47.80	($4.35)	($1.64)	$29.98	$30.95	($0.33)	($0.64)
AP	$47.69	$48.10	($0.40)	($0.01)	$31.50	$31.10	$0.35	$0.05
ATSI	$45.95	$52.72	($6.01)	($0.75)	$30.32	$31.02	($0.79)	$0.09
BGE	$57.18	$48.91	$6.06	$2.20	$36.38	$31.39	$3.48	$1.51
ComEd	$36.75	$47.87	($8.10)	($3.02)	$28.09	$31.05	($1.49)	($1.47)
DAY	$42.49	$48.35	($4.84)	($1.03)	$30.81	$31.12	($0.51)	$0.20
DEOK	NA	NA	NA	NA	$29.41	$31.13	($0.43)	($1.29)
DLCO	$41.75	$48.21	($5.10)	($1.35)	$30.31	$31.02	$0.11	($0.83)
Dominion	$54.64	$48.94	$4.93	$0.77	$33.09	$31.42	$1.25	$0.42
DPL	$55.43	$48.90	$3.74	$2.80	$33.74	$31.35	$1.10	$1.28
JCPL	$56.21	$49.21	$4.43	$2.57	$32.41	$31.63	($0.21)	$0.99
Met-Ed	$52.81	$48.29	$3.46	$1.05	$31.62	$31.20	$0.03	$0.39
PECO	$54.04	$48.52	$3.71	$1.81	$31.33	$31.26	($0.55)	$0.62
PENELEC	$47.07	$47.49	($0.86)	$0.45	$31.17	$30.89	($0.19)	$0.47
Pepco	$56.39	$48.96	$6.09	$1.33	$35.43	$31.42	$3.03	$0.97
PPL	$53.42	$48.09	$4.18	$1.14	$31.09	$31.14	($0.45)	$0.40
PSEG	$56.10	$48.58	$5.01	$2.51	$32.14	$31.30	($0.24)	$1.08
RECO	$50.25	$49.48	($1.51)	$2.28	$31.86	$31.79	($0.90)	$0.97
PJM	$48.47	$48.40	$0.05	$0.03	$31.21	$31.17	$0.04	$0.01

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2011 and 2012 (See 2011 SOM, Table 10-4)

	2011 (Jan-Jun)				2012 (Jan-Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.19	$47.79	$4.47	$2.92	$33.09	$32.13	($0.04)	$1.01
AEP	$41.40	$46.99	($3.76)	($1.83)	$30.56	$31.57	($0.28)	($0.74)
AP	$46.81	$47.02	($0.20)	($0.01)	$32.01	$31.68	$0.26	$0.08
ATSI	$46.35	$51.93	($4.59)	($0.99)	$30.75	$31.60	($0.75)	($0.09)
BGE	$55.10	$47.78	$4.96	$2.36	$37.29	$32.07	$3.46	$1.76
ComEd	$35.89	$46.72	($7.29)	($3.54)	$28.11	$31.72	($1.74)	($1.87)
DAY	$41.46	$47.33	($4.68)	($1.19)	$31.43	$31.84	($0.46)	$0.05
DEOK	NA	NA	NA	NA	$29.90	$31.69	($0.26)	($1.53)
DLCO	$40.51	$47.17	($5.25)	($1.41)	$31.20	$31.71	$0.34	($0.85)
Dominion	$52.73	$47.93	$4.17	$0.63	$33.91	$32.06	$1.29	$0.56
DPL	$55.24	$47.91	$4.01	$3.32	$34.55	$32.07	$0.86	$1.62
JCPL	$54.69	$47.74	$3.89	$3.07	$33.38	$32.22	$0.07	$1.09
Met-Ed	$51.54	$47.00	$3.44	$1.11	$32.25	$31.62	$0.20	$0.43
PECO	$53.90	$47.41	$4.16	$2.33	$32.34	$31.89	($0.25)	$0.70
PENELEC	$46.55	$46.96	($0.74)	$0.33	$31.97	$31.45	($0.09)	$0.61
Pepco	$54.75	$47.61	$5.50	$1.64	$36.10	$31.93	$2.85	$1.32
PPL	$52.43	$47.19	$4.08	$1.16	$31.65	$31.63	($0.30)	$0.32
PSEG	$55.30	$47.54	$4.62	$3.14	$33.46	$32.04	$0.12	$1.29
RECO	$51.84	$47.89	$1.53	$2.42	$32.87	$32.23	($0.42)	$1.06
PJM	$47.12	$47.32	($0.10)	($0.11)	$31.83	$31.76	$0.10	($0.02)

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy charge is based on the day-ahead and real-time energy components of LMP (SMP). Total energy charges, analogous to total congestion charges, are equal to the load energy payments minus generation energy credits, plus explicit energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Due to losses, total generation will be greater than total load in every hour. Since the hourly integrated energy component of LMP is the same across every bus in every hour, the net energy bill is negative, with more generation credits than load charges in any given hour. This net energy bill is netted against total net marginal loss charges plus net residual market adjustments, which provides for full recovery of generation charges, with any remainder distributed back to load and exports as marginal loss credits.

Total Energy Costs

Table 10-5 shows total energy, loss and congestion charges and total PJM billing, for the January through June period of each year from 2009 through 2012.

Table 10-5 Total PJM charges by component (Dollars (Millions)): January through June, 2009 through 2012[6] (See 2011 SOM, Table 10-5)

	PJM Billing Charges (Millions)					
(Jan-Jun)	Energy Charges	Loss Charges	Congestion Charges	Total Charges	Total PJM Billing	Total Charges Percent of PJM Billing
2009	($344)	$705	$309	$670	$13,457	5.0%
2010	($373)	$751	$345	$723	$16,314	4.4%
2011	($394)	$701	$361	$669	$18,685	3.6%
2012	($262)	$445	$123	$306	$13,991	2.2%

Total energy costs for the first six months for 2009 through 2012 are shown in Table 10-6 and Table 10-7. Table 10-6 shows PJM energy costs by category for the first six months of 2009 through 2012 and Table 10-7 shows PJM energy costs by market category for the first six months of 2009 through 2012.

Table 10-6 Total PJM energy costs by category (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-6)

	Energy Costs (Millions)				
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$22,815.7	$23,162.1	$0.0	$2.8	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($394.0)
2012	$16,823.7	$17,092.7	$0.0	$7.2	($261.7)

Table 10-7 Total PJM energy costs by market category (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-7)

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.8	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($394.0)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.4)	($56.2)	$0.0	($27.1)	$7.2	($261.7)

6 The Energy Charges, Loss Charges and Congestion Charges include net inadvertent charges.

Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for the first six months of 2011 and 2012.

Table 10-8 Monthly energy costs by type (Dollars (Millions)): January through June, 2011 and 2012 (See 2011 SOM, Table 10-8)

	Energy Costs (Millions)							
	2011 (Jan-Jun)				2012 (Jan-Jun)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($90.3)	($5.2)	$2.1	($93.3)	($48.5)	($10.1)	$2.5	($56.1)
Feb	($61.1)	($2.4)	$2.3	($61.2)	($36.0)	($9.9)	$2.4	($43.5)
Mar	($52.4)	($5.4)	$2.4	($55.4)	($30.1)	($8.6)	$1.9	($36.8)
Apr	($49.9)	($0.3)	$2.5	($47.7)	($30.7)	($2.8)	$0.7	($32.8)
May	($54.8)	($0.2)	$2.9	($52.1)	($39.4)	$0.3	($0.3)	($39.4)
Jun	($82.1)	($3.2)	$1.1	($84.2)	($57.1)	$4.0	$0.0	($53.1)
Total	($390.6)	($16.7)	$13.3	($394.0)	($241.9)	($27.1)	$7.2	($261.7)

Marginal Losses

Marginal Loss Accounting

PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system

Total loss charges, analogous to total congestion charges, are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Marginal loss charges can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January and as part of PJM for the second hour of January through June.

Monthly marginal loss costs in the first six months of 2012 ranged from $51.0 million in April to $95.2 million in January.

The marginal loss credits decreased by $126.3 million or 41.0 percent, from $308.4 million in the first six months of 2011 to $182.1 million in the first six months of 2012.

Total Calendar Year Marginal Loss Costs

Table 10-9 shows total marginal loss charges for the first six months for 2009 through 2012.

Table 10-9 Total[7] PJM Marginal Loss Charges (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-9)

(Jan-Jun)	Loss Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$705	NA	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%

Total marginal loss costs for the first six months for 2009 through 2012 are shown in Table 10-10 and Table 10-11. Table 10-10 shows PJM marginal loss costs by category for the first six months for 2009 through 2012. Table 10-11 shows PJM marginal loss costs by market category for the first six months for 2009 through 2012.

7 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 10-10 Total PJM marginal loss costs by category (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-10)

	Marginal Loss Costs (Millions)				
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.7)	$0.0	$444.8

Table 10-11 Total PJM marginal loss costs by market category (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-11)

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.4	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.8

Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for the first six months for 2011 and 2012.

Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): January through June, 2011 and 2012 (See 2011 SOM, Table 10-12)

	Marginal Loss Costs (Millions)							
	2011 (Jan-Jun)				2012 (Jan-Jun)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$188.5	($2.9)	$0.0	$185.7	$100.6	($5.4)	$0.0	$95.2
Feb	$121.8	($1.8)	$0.0	$119.9	$80.4	($3.1)	$0.0	$77.2
Mar	$108.8	($4.8)	$0.0	$104.0	$67.1	($5.2)	$0.0	$61.9
Apr	$84.8	($5.6)	$0.0	$79.2	$55.4	($4.4)	$0.0	$51.0
May	$94.3	($7.0)	$0.0	$87.3	$69.6	($2.5)	($0.0)	$67.1
Jun	$129.9	($4.5)	$0.0	$125.4	$93.3	($0.8)	$0.0	$92.4
Total	$728.1	($26.6)	$0.0	$701.5	$466.4	($21.6)	$0.0	$444.8

Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total net energy costs, the total net marginal loss costs and net residual market adjustments. The total energy costs are equal to the net energy costs (generation energy credits less load energy payments plus net inadvertent energy charges plus net explicit energy charges). Total marginal loss costs are equal to the net marginal loss costs (generation loss credits less load loss payments plus net inadvertent loss charges plus net explicit loss charges).

Ignoring interchange, total generation must be greater than total load in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same across every generator and load bus in every hour, the net energy bill will be negative (ignoring net interchange), with more generation credits than load charges collected in any given hour. This net energy bill is netted against total net marginal loss charges and net residual market adjustments, with the remainder distributed back to load and exports as marginal loss credits. Residual market adjustments consist of the known day-ahead error value, day-ahead loss MW congestion value and balancing loss MW congestion value. The known day-ahead error value is the financial calculation for the MW imbalance created when the day-ahead case is solved. The day-ahead and balancing loss MW congestion values are congestion values associated with loss MW that need to be deducted from the net of the total marginal loss costs, total energy costs and day-ahead known error value before marginal loss credits can be distributed.

Table 10-13 shows the total net energy charges, the total net marginal loss charges collected, the net residual market adjustments and total loss credits redistributed in the first six months for 2009 and 2012.

Table 10-13 Marginal[8] loss credits (Dollars (Millions)): January through June, 2009 through 2012 (See 2011 SOM, Table 10-13)

	Loss Credit Accounting (Millions)			
(Jan-Jun)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($343.6)	$704.8	($1.3)	$362.5
2010	($372.8)	$750.9	$0.6	$377.5
2011	($394.0)	$701.5	($0.9)	$308.4
2012	($261.7)	$444.8	$1.0	$182.1

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[9] Total congestion charges are equal to the net congestion bill plus explicit congestion charges plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[10]

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[11]

On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January and as part of PJM for the second hour of January through June.

8 Based on currently available data, the MMU is not able to independently calculate residual market adjustments. The adjustments numbers included in the table are comprised of the sum of the known day-ahead error value, day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data. In sum, these elements reflect the difference between actual PJM loss credits and MMU calculations of loss credits based on available data.

9 The terms congestion charges and congestion costs are both used to refer to the costs associated with congestion. The term congestion charges is used in documents by PJM's Market Settlement Operations.

10 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

11 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

Total Calendar Year Congestion

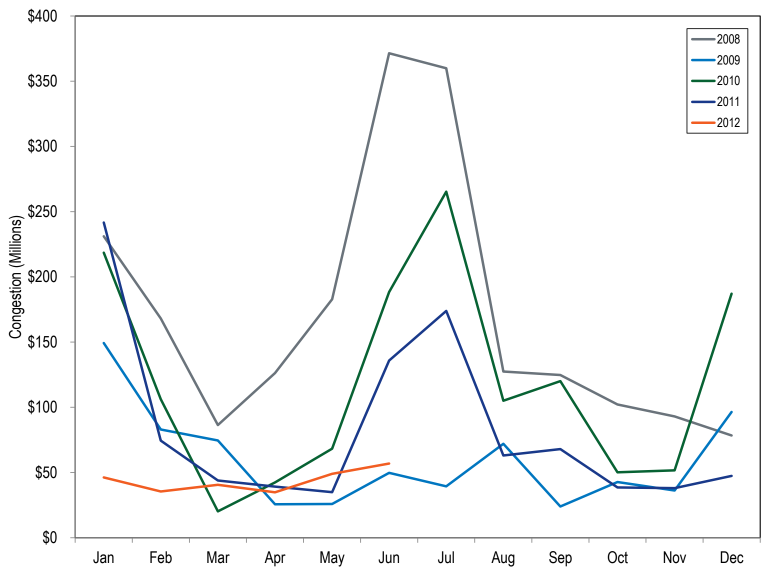
Table 10-14 shows total congestion from January through June by year from 2008 through 2012.[12]

Table 10-14 Total PJM congestion (Dollars (Millions)): January through June for calendar years 2008 to 2012 (See 2011 SOM, Table 10-14)

(Jan - Jun)	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166.1	NA	$24,172.0	4.8%
2009	$408.2	(65.0%)	$13,457.0	3.0%
2010	$644.0	57.8%	$16,314.0	3.9%
2011	$570.0	(11.5%)	$18,685.0	3.1%
2012	$263.2	(53.8%)	$13,991.0	1.9%

Figure 10-1 shows PJM monthly congestion for January 2008 through June 2012.

Figure 10-1 PJM monthly congestion (Dollars (Millions)): January 2008 to June 2012 (New Figure)



12 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*

Total congestion charges in Table 10-15 include congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO.[13]

Table 10-16 shows PJM congestion costs by category for the first six months of 2012. The January through June 2012 PJM total congestion costs were comprised of $60.5 million in load congestion payments, $239.1 million in negative generation congestion credits, and $36.4 million in negative explicit congestion costs.

Table 10-15 Total PJM congestion costs by category (Dollars (Millions)): January through June, 2011 and 2012 (See 2011 SOM, Table 10-15)

	Congestion Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2011	$104.0	($547.4)	($81.4)	$0.0	$570.0
2012	$60.5	($239.1)	($36.4)	$0.0	$263.2

13 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

Table 10-16 Total PJM congestion costs by market category (Dollars (Millions)): January through June, 2011 and 2012 (See 2011 SOM, Table 10-16)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2011	$59.6	($616.7)	$25.6	$701.9	$44.4	$69.3	($107.0)	($131.9)	$0.0	$570.0
2012	$61.7	($262.6)	$65.3	$389.6	($1.1)	$23.5	($101.7)	($126.4)	$0.0	$263.2

Monthly Congestion

Table 10-17 shows that during the first six months of 2012, monthly congestion charges ranged from $35.5 million to $56.9 million. Table 10-18 shows the congestion charges during the first six months of 2011.

With the exception of May, monthly congestion costs in 2012 were lower than for corresponding months in 2011.

Table 10-17 Monthly PJM congestion charges (Dollars (Millions)): January through June 2012 (See 2011 SOM, Table 10-17)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$4.0	($53.1)	$9.3	$66.3	$1.0	$5.7	($15.4)	($20.0)	$0.0	$46.3
Feb	$9.1	($38.3)	$7.4	$54.8	($3.7)	$2.7	($12.8)	($19.2)	$0.0	$35.5
Mar	$10.4	($38.5)	$10.9	$59.8	($1.7)	$3.7	($13.8)	($19.1)	$0.0	$40.7
Apr	$11.7	($43.7)	$16.5	$72.0	($3.2)	$5.2	($28.7)	($37.1)	$0.0	$34.9
May	$13.4	($37.2)	$16.6	$67.2	$0.5	($2.6)	($21.2)	($18.2)	$0.0	$49.0
Jun	$13.2	($51.7)	$4.6	$69.5	$5.9	$8.8	($9.8)	($12.7)	$0.0	$56.9
Total	$61.7	($262.6)	$65.3	$389.6	($1.1)	$23.5	($101.7)	($126.4)	$0.0	$263.2

Table 10-18 Monthly PJM congestion charges (Dollars (Millions)): January through June 2011 (See 2011 SOM, Table 10-18)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Jan	$27.0	($228.4)	$0.9	$256.4	$21.1	$15.6	($20.3)	($14.8)	$0.0	$241.6
Feb	$14.0	($77.5)	$1.0	$92.5	$5.6	$12.8	($10.9)	($18.0)	$0.0	$74.5
Mar	($2.5)	($58.8)	$2.2	$58.4	$0.2	$4.7	($10.0)	($14.6)	$0.0	$43.9
Apr	$5.0	($56.5)	$6.6	$68.0	$1.4	$6.4	($23.7)	($28.8)	$0.0	$39.2
May	$14.3	($41.5)	$8.6	$64.3	$3.0	$7.4	($24.9)	($29.3)	$0.0	$35.0
Jun	$1.8	($154.0)	$6.4	$162.3	$13.1	$22.4	($17.1)	($26.4)	$0.0	$135.9
Total	$59.6	($616.7)	$25.6	$701.9	$44.4	$69.3	($107.0)	($131.9)	$0.0	$570.0

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within a year.

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 also consistent with the way in which PJM reports real-time congestion. In the first six months of 2012, there were 106,091 day-ahead, congestion-event hours compared to 57,969 day-ahead, congestion-event hours in the first six months of 2011. In the first six months of 2012, there were 9,244 real-time, congestion-event hours compared to 9,483 real-time, congestion-event hours in the first six months of 2011.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. Virtual transactions in the Day-Ahead Market can be used to discretely resolve, without eliminating, constraints on the transmission system. Relative to the Day-Ahead Market, the Real-Time Market has relatively inflexible resources to resolve transmission constraints which means that constraints are often eliminated, rather than discretely controlled.

During the first six months of 2012, for only 3.7 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first six months of 2012, for 41.7 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The Graceton – Raphael Road transmission line was the largest contributor to congestion costs in the first six months of 2012. With $30.8 million in total congestion costs, it accounted for 11.7 percent of the total PJM congestion costs in the first six months of 2012. The top five constraints in terms of congestion costs together contributed $82.7 million, or 31.4 percent, of the total PJM congestion costs in the first six months of 2012. The top five constraints were the Graceton – Raphael Road transmission line, Woodstock flowgate, AP South interface, Belvidere – Woodstock line and West interface.

Congestion by Facility Type and Voltage

In the first six months of 2012, compared to the first six months of 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transmission lines, while congestion frequency on interfaces and transformers decreased.

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO in the first six months of 2012 compared to the first six months of 2011 and decreased on PJM interfaces, transmission lines and transformers in the first six months of 2012 compared to the first six months of 2011. Balancing congestion costs decreased on the reciprocally coordinated flowgates between PJM and MISO and PJM interfaces and increased on transformers and transmission lines in the first six months of 2012 compared to first six months of 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first six months of 2012 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[14,15] For comparison, this information is presented in Table 10-20 for the first six months of 2011.[16]

14 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

15 The term flowgate refers to MISO flowgates.

16 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs

Table 10-19 Congestion summary (By facility type): January through June 2012 (See 2011 SOM, Table 10-19)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($28.6)	($100.5)	$29.7	$101.5	($0.4)	$6.7	($56.9)	($64.1)	$37.5	13,838	3,239
Interface	$19.9	($41.2)	($2.3)	$58.8	$6.6	$8.4	($1.6)	($3.4)	$55.5	2,701	254
Line	$45.4	($84.8)	$29.6	$159.7	($8.8)	$6.6	($39.0)	($54.5)	$105.3	63,028	4,567
Other	$8.0	($3.7)	$0.8	$12.5	($0.7)	($0.1)	($0.8)	($1.5)	$11.0	1,993	411
Transformer	$16.5	($31.0)	$6.2	$53.6	$2.1	$1.7	($3.2)	($2.8)	$50.9	24,531	753
Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	NA	NA
Total	$61.7	($262.6)	$65.3	$389.6	($1.1)	$23.5	($101.7)	($126.4)	$263.2	106,091	9,224

Table 10-20 Congestion summary (By facility type): January through June 2011 (See 2011 SOM, Table 10-20)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($52.3)	($103.4)	$6.1	$57.2	$7.0	$8.9	($42.6)	($44.5)	$12.7	9,530	2,666
Interface	$53.6	($272.1)	($5.9)	$319.9	$21.4	$22.0	$4.1	$3.5	$323.4	4,706	1,095
Line	$37.5	($136.8)	$11.9	$186.2	$13.2	$27.6	($40.3)	($54.8)	$131.4	30,405	3,798
Other	($0.3)	($1.2)	$0.6	$1.5	$1.1	$1.3	$0.1	($0.1)	$1.4	441	71
Transformer	$20.9	($101.4)	$9.1	$131.4	$0.9	$9.4	($27.2)	($35.7)	$95.7	12,887	1,853
Unclassified	$0.3	($1.8)	$3.8	$5.9	$0.7	$0.0	($1.1)	($0.4)	$5.5	NA	NA
Total	$59.6	($616.7)	$25.6	$701.9	$44.4	$69.3	($107.0)	($131.9)	$570.0	57,969	9,483

Table 10-21 and Table 10-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 10-21. In the first six months of 2012, there were 106,091 congestion event hours in the Day-Ahead Market. Among those, only 3,908 (3.7 percent) were also constrained in the Real-Time Market. In the first six months of 2011, among the 57,969 day-ahead congestion event hours, only 4,167 (7.2 percent) were binding in the Real-Time Market.[17]

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In the first six months of 2012, there 9,224 congestion event hours in the Real-Time Market. Among these, 3,849 (41.7percent) were also constrained in the Day-Ahead Market. In the first six months of 2011, among the 9,483 real-time congestion event hours, only 4,134 (43.6 percent) were binding in the day-ahead.

17 Both regular and contingency constraints are mapped to transmission facilities. In the day-ahead market, within a given hour, a single facility may be associated with both regular and multiple contingency constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour. The result is that the number of hours where real time constraints are observed in day-ahead market results may not match.

Table 10-21 Congestion Event Hours (Day-Ahead against Real Time): January through June 2011 and 2012 (See 2011 SOM, Table 10-21)

	Congestion Event Hours					
	2012 (Jan - Jun)			2011 (Jan - Jun)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	13,838	1,462	10.6%	9,530	1,285	13.5%
Interface	2,701	105	3.9%	4,706	774	16.4%
Line	63,028	1,824	2.9%	30,405	1,211	4.0%
Other	1,993	258	12.9%	441	0	0.0%
Transformer	24,531	259	1.1%	12,887	897	7.0%
Total	106,091	3,908	3.7%	57,969	4,167	7.2%

Table 10-22 Congestion Event Hours (Real Time against Day-Ahead): January through June 2011 and 2012 (See 2011 SOM, Table 10-22)

	Congestion Event Hours					
	2012 (Jan - Jun)			2011 (Jan - Jun)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	3,239	1,516	46.8%	2,666	1,291	48.4%
Interface	254	103	40.6%	1,095	773	70.6%
Line	4,567	1,757	38.5%	3,798	1,184	31.2%
Other	411	222	54.0%	71	0	0.0%
Transformer	753	251	33.3%	1,853	886	47.8%
Total	9,224	3,849	41.7%	9,483	4,134	43.6%

Table 10-23 shows congestion costs by facility voltage class for the first six months of 2012. In comparison to the first six months of 2011 (shown in Table 10-24), congestion costs decreased across 765 kV, 500kV, 345 kV and 230kV in the first six months of 2012.

Table 10-23 Congestion summary (By facility voltage): January through June 2012 (See 2011 SOM, Table 10-23)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.2)	($2.4)	$2.2	$4.4	$0.1	($0.0)	($0.1)	($0.0)	$4.4	1,648	78
500	$23.0	($49.4)	($0.9)	$71.5	$7.0	$8.4	($3.2)	($4.6)	$66.9	5,147	400
345	($15.1)	($53.8)	$8.3	$46.9	$0.8	$2.9	($20.9)	($23.0)	$23.9	14,565	1,226
230	$45.5	($28.6)	$5.3	$79.4	$2.0	$3.2	($8.2)	($9.4)	$70.0	18,771	2,160
161	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,942	717
138	($9.0)	($117.1)	$40.4	$148.5	($5.3)	$6.6	($57.7)	($69.5)	$78.9	51,772	3,915
115	$15.7	($0.5)	$2.1	$18.3	($0.4)	$0.6	($0.6)	($1.7)	$16.6	8,713	484
69	$7.2	$0.3	$1.0	$7.9	($4.9)	$0.8	($1.2)	($6.9)	$1.0	3,524	244
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$0.5	($1.5)	$1.5	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.2	NA	NA
Total	$61.7	($262.6)	$65.3	$389.6	($1.1)	$23.5	($101.7)	($126.4)	$263.2	106,091	9,224

Table 10-24 Congestion summary (By facility voltage): January through June 2011 (See 2011 SOM, Table 10-24)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.7	($4.1)	$1.1	$5.9	$2.6	$1.9	($2.1)	($1.4)	$4.5	288	100
500	$78.0	($316.5)	($5.7)	$388.8	$25.5	$30.7	($8.2)	($13.5)	$375.3	10,385	2,335
345	($43.5)	($118.8)	$6.8	$82.1	$6.4	$16.5	($42.2)	($52.4)	$29.7	11,127	1,710
230	($3.2)	($93.9)	$6.2	$97.0	$7.3	$8.9	($21.0)	($22.5)	$74.4	9,715	1,339
161	($7.5)	($11.4)	$4.0	$7.9	($0.7)	$2.4	($11.1)	($14.2)	($6.3)	891	418
138	$23.6	($65.1)	$7.4	$96.1	$2.7	$6.2	($20.6)	($24.1)	$72.0	17,918	3,129
115	$6.5	($2.8)	$2.0	$11.2	$0.7	$2.0	($0.4)	($1.7)	$9.6	3,661	318
69	$4.8	($2.4)	($0.1)	$7.2	($0.8)	$0.8	($0.3)	($1.9)	$5.3	3,967	134
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
Unclassified	$0.3	($1.8)	$3.8	$5.9	$0.7	$0.0	($1.1)	($0.4)	$5.5	NA	NA
Total	$59.6	($616.7)	$25.6	$701.9	$44.4	$69.3	($107.0)	($131.9)	$570.0	57,959	9,483

Constraint Duration

Table 10-25 lists constraints in the first six months of 2011 and 2012 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from the first six months of 2011 to the first six months of 2012.

Table 10-25 Top 25 constraints with frequent occurrence: January through June 2011 and 2012 (See 2011 SOM, Table 10-25)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	0	4,999	4,999	0	0	0	0%	57%	57%	0%	0%	0%
2	Graceton - Raphael Road	Line	53	2,331	2,278	50	616	566	1%	27%	26%	1%	7%	6%
3	Oak Grove - Galesburg	Flowgate	891	1,942	1,051	418	717	299	10%	22%	12%	5%	8%	3%
4	Kammer	Transformer	0	2,260	2,260	10	11	1	0%	26%	26%	0%	0%	0%
5	Monticello - East Winamac	Flowgate	207	1,666	1,459	100	541	441	2%	19%	17%	1%	6%	5%
6	Linden - VFT	Line	1,128	2,150	1,022	0	0	0	13%	24%	12%	0%	0%	0%
7	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
8	Crete - St Johns Tap	Flowgate	2,439	1,766	(673)	605	268	(337)	28%	20%	(8%)	7%	3%	(4%)
9	Cumberland - Bush	Flowgate	835	1,651	816	140	283	143	10%	19%	9%	2%	3%	2%
10	Huntingdon - Huntingdon1	Line	0	1,933	1,933	0	0	0	0%	22%	22%	0%	0%	0%
11	Belmont	Transformer	2,521	1,723	(798)	248	60	(188)	29%	20%	(9%)	3%	1%	(2%)
12	Hillsdale - New Milford	Line	0	1,331	1,331	0	259	259	0%	15%	15%	0%	3%	3%
13	Conesville	Transformer	0	1,514	1,514	0	0	0	0%	17%	17%	0%	0%	0%
14	Wolfcreek	Transformer	1,257	1,480	223	128	9	(119)	14%	17%	2%	1%	0%	(1%)
15	Howard - Shelby	Line	0	1,450	1,450	0	0	0	0%	17%	17%	0%	0%	0%
16	Conesville	Transformer	0	1,445	1,445	0	0	0	0%	16%	16%	0%	0%	0%
17	Belvidere - Woodstock	Line	162	675	513	18	736	718	2%	8%	6%	0%	8%	8%
18	Big Sandy - Grangston	Line	29	1,362	1,333	0	0	0	0%	16%	15%	0%	0%	0%
19	Danville - East Danville	Line	1,234	1,358	124	284	0	(284)	14%	15%	1%	3%	0%	(3%)
20	Redoak - Sayreville	Line	432	1,328	896	0	0	0	5%	15%	10%	0%	0%	0%
21	Brues - West Bellaire	Line	823	1,223	400	283	57	(226)	9%	14%	5%	3%	1%	(3%)
22	AP South	Interface	2,027	1,195	(832)	629	82	(547)	23%	14%	(10%)	7%	1%	(6%)
23	Foster2 - Pierce	Line	0	1,171	1,171	1	11	10	0%	13%	13%	0%	0%	0%
24	Sheffield - Marktown	Flowgate	0	1,055	1,055	0	66	66	0%	12%	12%	0%	1%	1%
25	Silver Lake - Pleasant Valley	Line	0	1,099	1,099	0	0	0	0%	13%	13%	0%	0%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through June 2011 and 2012 (See 2011 SOM, Table 10-26)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	0	4,999	4,999	0	0	0	0%	57%	57%	0%	0%	0%
2	South Mahwah - Waldwick	Line	2,941	51	(2,890)	419	0	(419)	34%	1%	(33%)	5%	0%	(5%)
3	Graceton - Raphael Road	Line	53	2,331	2,278	50	616	566	1%	27%	26%	1%	7%	6%
4	Kammer	Transformer	0	2,260	2,260	10	11	1	0%	26%	26%	0%	0%	0%
5	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
6	Wylie Ridge	Transformer	1,842	182	(1,660)	351	2	(349)	21%	2%	(19%)	4%	0%	(4%)
7	Huntingdon - Huntingdon1	Line	0	1,933	1,933	0	0	0	0%	22%	22%	0%	0%	0%
8	Monticello - East Winamac	Flowgate	207	1,666	1,459	100	541	441	2%	19%	17%	1%	6%	5%
9	Hillsdale - New Milford	Line	0	1,331	1,331	0	259	259	0%	15%	15%	0%	3%	3%
10	Conesville	Transformer	0	1,514	1,514	0	0	0	0%	17%	17%	0%	0%	0%
11	Howard - Shelby	Line	0	1,450	1,450	0	0	0	0%	17%	17%	0%	0%	0%
12	Conesville	Transformer	0	1,445	1,445	0	0	0	0%	16%	16%	0%	0%	0%
13	AP South	Interface	2,027	1,195	(832)	629	82	(547)	23%	14%	(10%)	7%	1%	(6%)
14	Oak Grove - Galesburg	Flowgate	891	1,942	1,051	418	717	299	10%	22%	12%	5%	8%	3%
15	Big Sandy - Grangston	Line	29	1,362	1,333	0	0	0	0%	16%	15%	0%	0%	0%
16	Fairview	Transformer	1,287	0	(1,287)	0	0	0	15%	0%	(15%)	0%	0%	0%
17	Belvidere - Woodstock	Line	162	675	513	18	736	718	2%	8%	6%	0%	8%	8%
18	Foster2 - Pierce	Line	0	1,171	1,171	1	11	10	0%	13%	13%	0%	0%	0%
19	Cox's Corner - Marlton	Line	1,635	468	(1,167)	0	0	0	19%	5%	(13%)	0%	0%	0%
20	Sheffield - Marktown	Flowgate	0	1,055	1,055	0	66	66	0%	12%	12%	0%	1%	1%
21	Silver Lake - Pleasant Valley	Line	0	1,099	1,099	0	0	0	0%	13%	13%	0%	0%	0%
22	Belvidere - Woodstock	Flowgate	0	1,073	1,073	0	0	0	0%	12%	12%	0%	0%	0%
23	Linden - VFT	Line	1,128	2,150	1,022	0	0	0	13%	24%	12%	0%	0%	0%
24	Crete - St Johns Tap	Flowgate	2,439	1,766	(673)	605	268	(337)	28%	20%	(8%)	7%	3%	(4%)
25	Northwest	Other	0	584	584	0	402	402	0%	7%	7%	0%	5%	5%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for the periods January through June 2012 and 2011.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): January through June 2012 (See 2011 SOM, Table 10-27)

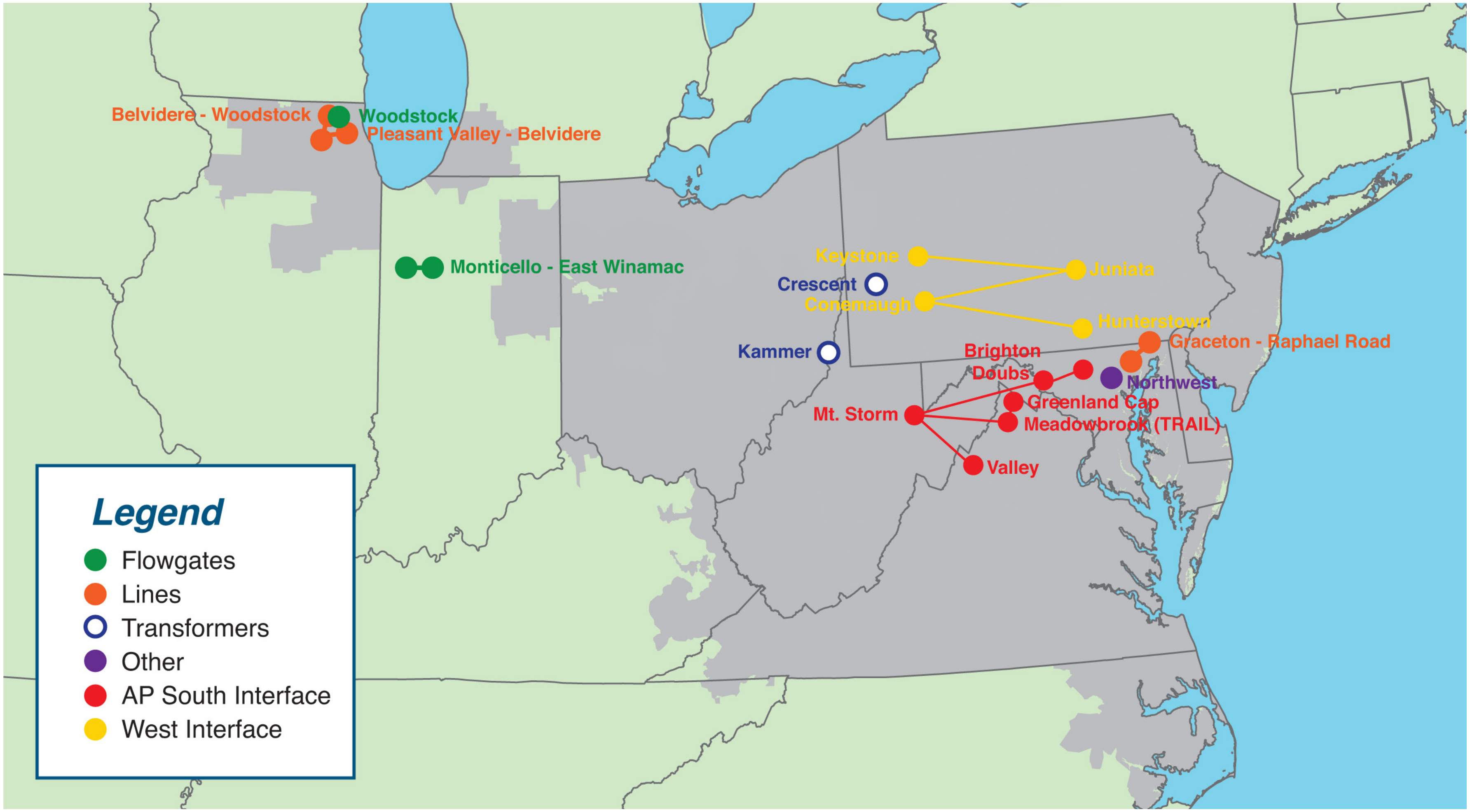
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2012 (Jan - Jun)
1	Graceton - Raphael Road	Line	BGE	$23.6	($7.8)	($1.8)	$29.5	($0.1)	($0.6)	$0.9	$1.3	$30.8	12%
2	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	11%
3	AP South	Interface	500	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.3	10%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.6)	$1.0	$5.3	($2.4)	$3.2	($16.9)	($22.5)	($17.2)	(7%)
5	West	Interface	500	($1.1)	($17.1)	($2.3)	$13.7	$1.1	$1.2	$0.3	$0.1	$13.8	5%
6	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	3%
7	Pleasant Valley - Belvidere	Line	ComEd	($2.1)	($7.9)	$1.8	$7.5	$0.1	$0.1	($0.8)	($0.7)	$6.8	3%
8	Monticello - East Winamac	Flowgate	MISO	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	2%
9	Kammer	Transformer	AEP	($2.3)	($8.5)	($1.0)	$5.2	($0.2)	$0.1	$0.2	($0.0)	$5.1	2%
10	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.1	($0.1)	$0.0	$5.1	2%
11	Hunterstown	Transformer	Met-Ed	$1.4	($3.4)	$0.2	$5.0	$0.1	$0.0	($0.0)	$0.0	$5.0	2%
12	Belmont	Transformer	AP	$0.6	($5.4)	$0.5	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	2%
13	Breed - Wheatland	Flowgate	MISO	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	(2%)
14	Electric Jct - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	2%
15	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	2%
16	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$1.9	$2.4	$0.5	($0.0)	$4.5	2%
17	Loudoun - Gainsville	Line	Dominion	($0.0)	($5.0)	($0.5)	$4.4	$0.4	$0.6	$0.2	($0.0)	$4.4	2%
18	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	2%
19	Bedington - Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	2%
20	Lancaster - Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.6	($0.4)	$0.6	($3.5)	($4.4)	($3.8)	(1%)
21	Unclassified	Unclassified	Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	1%
22	AEP-DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	1%
23	Hillsdale - New Milford	Line	PSEG	$0.2	($0.6)	$4.3	$5.1	$0.1	$1.1	($7.2)	($8.1)	($3.0)	(1%)
24	Three Mile Island	Transformer	Met-Ed	$1.3	($1.0)	$0.7	$2.9	$0.3	($1.0)	($1.3)	$0.1	$3.0	1%
25	Brues - West Bellaire	Line	AEP	$2.0	($1.4)	($0.5)	$2.9	($0.0)	$0.1	$0.1	($0.0)	$2.9	1%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through June 2011 (See 2011 SOM, Table 10-28)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011 (Jan - Jun)
1	AP South	Interface	500	$69.2	($105.7)	$0.5	$175.3	$12.6	$12.1	($0.2)	$0.3	$175.7	31%
2	5004/5005 Interface	Interface	500	($22.1)	($86.0)	($4.4)	$59.4	$7.5	$8.0	$4.4	$3.9	$63.3	11%
3	Belmont	Transformer	AP	$6.8	($32.4)	($2.7)	$36.6	($2.1)	($1.7)	($0.7)	($1.2)	$35.4	6%
4	AEP-DOM	Interface	500	$11.7	($16.6)	$1.6	$30.0	$0.7	$0.5	($0.1)	$0.0	$30.0	5%
5	West	Interface	500	($10.0)	($34.9)	($1.3)	$23.6	$0.2	$0.1	$0.1	$0.3	$23.9	4%
6	Bedington - Black Oak	Interface	500	$10.6	($14.3)	($2.0)	$22.9	($0.0)	($0.0)	($0.0)	$0.0	$22.9	4%
7	Crete - St Johns Tap	Flowgate	MISO	($25.9)	($49.7)	($3.8)	$20.0	$5.0	$4.1	($2.3)	($1.4)	$18.6	3%
8	Dickerson - Quince Orchard	Line	Pepco	($8.7)	($25.7)	($1.5)	$15.6	$4.0	$6.6	$2.5	($0.1)	$15.5	3%
9	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	3%
10	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.5	$2.2	$1.2	($2.5)	($1.5)	$12.0	2%
11	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($10.0)	(2%)
12	Dooms	Transformer	Dominion	$0.4	($0.1)	$0.2	$0.8	($2.4)	$2.8	($4.6)	($9.8)	($9.1)	(2%)
13	Clover	Transformer	Dominion	$0.0	($10.8)	$2.1	$13.0	$0.8	$1.4	($3.7)	($4.3)	$8.7	2%
14	Electric Jct - Nelson	Line	ComEd	($3.4)	($15.4)	$3.3	$15.3	$0.7	$2.7	($5.3)	($7.3)	$8.0	1%
15	South Mahwah - Waldwick	Line	PSEG	($5.2)	($22.3)	($1.1)	$16.0	($0.9)	$5.4	($17.0)	($23.2)	($7.2)	(1%)
16	East	Interface	500	($4.5)	($12.3)	($0.2)	$7.6	$0.2	$1.3	$0.1	($1.0)	$6.6	1%
17	Oak Grove - Galesburg	Flowgate	MISO	($7.5)	($11.4)	$4.0	$7.9	($0.7)	$2.4	($11.1)	($14.2)	($6.3)	(1%)
18	Cloverdale - Lexington	Line	500	$4.1	($2.5)	$0.8	$7.4	$3.0	$1.6	($2.5)	($1.2)	$6.2	1%
19	Bunsonville - Eugene	Flowgate	MISO	($6.2)	($11.3)	$1.0	$6.2	$0.0	$0.0	$0.0	$0.0	$6.2	1%
20	Brues - West Bellaire	Line	AEP	$12.6	$3.1	$0.3	$9.8	($1.2)	$1.6	($0.9)	($3.7)	$6.1	1%
21	Unclassified	Unclassified	Unclassified	$0.3	($1.8)	$3.8	$5.9	$0.7	$0.0	($1.1)	($0.4)	$5.5	1%
22	Cloverdale	Transformer	AEP	$0.4	($3.4)	$0.8	$4.6	$0.5	$0.4	$0.1	$0.2	$4.7	1%
23	Yukon	Transformer	AP	($2.0)	($6.4)	($0.2)	$4.1	$0.1	($0.1)	$0.3	$0.5	$4.7	1%
24	Danville - East Danville	Line	AEP	$18.9	$11.4	($2.3)	$5.3	$1.3	$1.0	($1.1)	($0.8)	$4.5	1%
25	East Frankfort - Crete	Line	ComEd	($2.8)	($7.0)	$0.1	$4.4	$0.0	$0.0	($0.0)	$0.0	$4.4	1%

Figure 10-2 shows the locations of the top 10 constraints affecting PJM congestion costs in the first six months of 2012.

Figure 10-2 Location of the top 10 constraints affecting PJM congestion costs: January through June 2012 (New Figure)



Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[18] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[19] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first six months of 2012 and 2011 respectively, and which had the greatest congestion cost impact on PJM. 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. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first six months of 2012, the Woodstock flowgate made the most significant contribution to positive congestion while the Breed - Wheatland flowgate made the most significant contribution to negative congestion.

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 2012 (See 2011 SOM, Table 10-29)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	0
2	Monticello - East Winamac	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	1,666	541
3	Breed - Wheatland	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	692	224
4	Crete - St Johns Tap	($4.6)	($14.7)	($1.2)	$8.8	$0.3	$1.0	($5.4)	($6.1)	$2.7	1,766	268
5	Oak Grove - Galesburg	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,942	717
6	Cumberland - Bush	($1.0)	($5.0)	$5.6	$9.5	$0.4	$1.2	($10.3)	($11.1)	($1.6)	1,651	283
7	Miami Fort - Hebron	($0.6)	($1.9)	$0.1	$1.4	($0.1)	($0.0)	$0.1	$0.0	$1.4	455	58
8	Prairie State - W Mt. Vernon	($1.6)	($2.6)	$0.5	$1.5	($0.0)	($0.0)	($0.2)	($0.2)	$1.3	422	156
9	Bunsonville - Eugene	($0.7)	($1.2)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	37
10	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
11	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	4
12	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	66
13	Edwards - Kewanee	($0.3)	($0.5)	$0.4	$0.7	$0.0	($0.0)	($0.2)	($0.2)	$0.5	127	36
14	Palisades - Roosevelt	($0.2)	($1.0)	($0.2)	$0.6	$0.0	($0.0)	($0.2)	($0.1)	$0.5	152	42
15	Beaver Channel - Albany	($1.6)	($5.1)	$0.8	$4.2	($1.3)	$0.6	($2.7)	($4.7)	($0.5)	336	111
16	Burnham - Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	226	0
17	Lanesville	$0.1	($0.0)	$0.6	$0.7	($0.0)	$0.0	($0.2)	($0.3)	$0.4	282	21
18	Roxana - Praxair	($0.0)	($0.5)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	135	0
19	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	14
20	Kenosha - Lakeview	($0.0)	($0.3)	$0.1	$0.4	($0.1)	$0.1	($0.6)	($0.7)	($0.3)	101	99

18 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

19 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 2011 (See 2011 SOM, Table 10-30)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	$1.3	($24.0)	($3.8)	$21.4	$4.4	$3.4	($2.5)	($1.6)	$19.8	2,673	607
2	Bunsonville - Eugene	($1.4)	($7.3)	$1.3	$7.2	$0.0	$0.0	$0.0	$0.0	$7.2	1,543	0
3	Oak Grove - Galesburg	($2.4)	($6.6)	$4.2	$8.4	($0.8)	$2.3	($11.7)	($14.8)	($6.4)	1,011	525
4	Lakeview - Pleasant Prairie	($0.0)	($0.1)	$0.2	$0.3	($0.2)	($0.0)	($5.4)	($5.6)	($5.3)	24	279
5	Pleasant Prairie - Zion	($0.8)	($1.9)	$2.0	$3.1	($0.0)	($0.4)	($7.9)	($7.5)	($4.4)	832	210
6	Michigan City - Laporte	$1.1	($4.1)	$2.0	$7.1	($1.1)	($1.2)	($3.0)	($3.0)	$4.1	2,008	442
7	Kenosha - Lakeview	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.5)	($4.3)	($3.8)	($3.8)	0	305
8	Cook - Palisades	$0.9	($2.3)	$0.2	$3.5	$0.0	$0.0	($0.2)	($0.2)	$3.2	419	9
9	Kenosha - Lakeview	$1.2	($1.2)	$0.8	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	886	0
10	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.1	$0.3	($1.5)	($1.7)	($1.7)	0	47
11	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($1.6)	($1.7)	($1.7)	0	71
12	Benton Harbor - Palisades	$0.7	($0.1)	$0.2	$1.0	$1.0	$0.9	($2.7)	($2.5)	($1.6)	67	107
13	Rantoul Jct - Sidney	($0.3)	($1.3)	$0.1	$1.1	$0.5	($0.0)	($0.3)	$0.2	$1.3	62	113
14	Burr Oak	$0.4	($0.6)	$0.0	$1.0	$0.2	($0.1)	($0.2)	$0.0	$1.0	135	20
15	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.5	$0.3	($1.2)	($1.0)	($1.0)	0	16
16	Rantoul - Rantoul Jct	$0.0	($0.9)	$0.2	$1.1	$0.1	($0.0)	($0.3)	($0.2)	$0.9	184	89
17	Miami Fort	($0.0)	($0.6)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	96	0
18	Babcock - Stillwell	$0.0	$0.0	$0.0	$0.0	$0.6	$0.6	($0.6)	($0.6)	($0.6)	0	57
19	State Line - Wolf Lake	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.5)	($0.5)	($0.5)	0	29
20	Cumberland - Bush	($0.1)	($2.4)	$0.7	$3.0	$0.2	$0.2	($2.5)	($2.5)	$0.4	861	159

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for the first six months of 2012 and 2011 respectively. 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. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 10-31 Regional constraints summary (By facility): January through June 2012 (See 2011 SOM, Table 10-31)

				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	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.3	1,195	82
2	West	Interface	500	($1.1)	($17.1)	($2.3)	$13.7	$1.1	$1.2	$0.3	$0.1	$13.8	318	14
3	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$1.9	$2.4	$0.5	($0.0)	$4.5	152	83
4	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	177	5
5	Bedington - Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	134	16
6	AEP-DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	543	52
7	Doubs - Mount Storm	Line	500	$1.3	($1.1)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	80	0
8	Central	Interface	500	($0.7)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	182	2
9	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
10	Burches Hill - Chalk Point	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Table 10-32 Regional constraints summary (By facility): January through June 2011 (See 2011 SOM, Table 10-32)

				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	($8.1)	($208.9)	($1.3)	$199.4	$10.5	$9.0	$0.6	$2.1	$201.5	2,917	756
2	5004/5005 Interface	Interface	500	$57.2	($12.7)	($4.7)	$65.2	$12.9	$15.3	$7.1	$4.8	$70.0	609	411
3	West	Interface	500	$66.9	$11.1	($5.3)	$50.5	$0.2	$0.0	$0.1	$0.3	$50.7	797	19
4	AEP-DOM	Interface	500	$2.6	($26.2)	$1.5	$30.3	$0.8	$0.5	($0.0)	$0.3	$30.6	1,067	125
5	Bedington - Black Oak	Interface	500	$5.4	($19.5)	($2.0)	$22.9	($0.0)	($0.0)	($0.0)	$0.0	$22.9	624	1
6	East	Interface	500	$11.0	($5.5)	($1.1)	$15.4	$0.1	$1.2	$0.1	($1.0)	$14.4	289	22
7	Central	Interface	500	$1.5	$0.4	($0.1)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	63	0
8	Harrison - Pruntytown	Line	500	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
9	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	0	38
10	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	4
11	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	0	9

Congestion Costs by Physical and Financial Participants

In the PJM market, both physical and financial participants make virtual supply offers (increments) and virtual demand bids (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are considered a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company.

In the first six months of 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first six months of 2012, financial companies received $41.4 million in net congestion credits, a decrease of $23.7 million or 36.4 percent compared to the first six months of 2011. In the first six months of 2012, physical companies paid $304.6 million in net congestion charges, a decrease of $330.5 million or 52.0 percent compared to the first six months of 2011.

Table 10-33 Congestion cost by the type of the participant: January through June 2012 (See 2011 SOM, Table 10-33)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$5.8	($0.0)	$45.7	$51.5	($15.4)	($2.1)	($79.7)	($93.0)	$0.0	($41.4)
Physical	$55.9	($262.6)	$19.6	$338.0	$14.3	$25.6	($22.1)	($33.4)	$0.0	$304.6
Total	$61.7	($262.6)	$65.3	$389.6	($1.1)	$23.5	($101.7)	($126.4)	$0.0	$263.2

Table 10-34 Congestion cost by the type of the participant: January through June 2011 (See 2011 SOM, Table 10-34)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$26.4	$1.7	$31.7	$56.3	($18.2)	$2.0	($101.2)	($121.4)	$0.0	($65.1)
Physical	$33.3	($618.4)	($6.0)	$645.7	$62.6	$67.3	($5.9)	($10.5)	$0.0	$635.1
Total	$59.6	($616.7)	$25.6	$701.9	$44.4	$69.3	($107.0)	($131.9)	$0.0	$570.0