Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at a 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.

Highlights

- Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012 (Table 10-10).
- Day-ahead marginal loss costs decreased by $415.0 million or 34.8 percent, from $1,191.1 million in the first nine months of 2011 to $776.0 million in the first nine months of 2012 (Table 10-12).
- Balancing marginal loss costs increased by $20.0 million or 52.0 percent, from $38.5 million in the first nine months of 2011 to -$18.5 million in the first nine months of 2012 (Table 10-12).
- The marginal loss credits (loss surplus) decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012. (Table 10-13).
- Congestion decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine months of 2012 (Table 10-15).
- Day-ahead congestion costs decreased by 460.0 million or 43.3 percent, from $1,063.2 million in the first nine months of 2011 to $603.2 million in the first nine months of 2012.
- Balancing congestion costs decreased by $10.3 million or 5.8 percent, from -$178.0 million in the first nine months of 2011 to -$188.3 million in the first nine 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. Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and

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. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

geographic distribution of generation facilities and the geographic distribution of load. Congestion costs decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine 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 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 73.8 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 79.1 percent of the target allocation level for the first four months of the 2012 to 2013 planning period.[2] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion generally refers to what is actually net congestion, which is calculated as load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first nine months for years 2009 to 2012.[3]

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

(Jan-Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01

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

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

(Jan-Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$39.95	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for January through September, 2011 and 2012. The day-ahead components of LMP for each control zone are presented in Table 10-4 for January through September, 2011 and 2012.

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

3 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 September, 2012.

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

	2011 (Jan-Sep)				2012 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.81	$50.11	$4.95	$2.75	$37.23	$35.88	($0.01)	$1.37
AEP	$42.97	$48.64	($3.99)	($1.68)	$32.81	$34.39	($0.82)	($0.77)
AP	$48.57	$48.99	($0.22)	($0.20)	$34.63	$34.61	$0.12	($0.10)
ATSI	$46.88	$51.24	($3.85)	($0.51)	$33.98	$34.71	($0.91)	$0.18
BGE	$58.74	$49.82	$6.62	$2.30	$40.16	$35.29	$3.28	$1.58
ComEd	$38.97	$49.12	($7.32)	($2.83)	$32.35	$35.27	($1.51)	($1.41)
DAY	$43.90	$49.40	($4.57)	($0.93)	$33.97	$34.88	($1.08)	$0.17
DEOK	NA	NA	NA	NA	$32.41	$34.95	($1.03)	($1.52)
DLCO	$43.30	$49.12	($4.15)	($1.67)	$33.44	$34.81	($0.37)	($1.01)
Dominion	$54.47	$49.83	$4.04	$0.60	$37.21	$35.29	$1.62	$0.31
DPL	$56.76	$49.95	$3.82	$2.99	$39.43	$35.40	$2.41	$1.62
JCPL	$58.09	$50.73	$4.62	$2.74	$36.95	$36.02	($0.25)	$1.17
Met-Ed	$53.64	$49.22	$3.42	$1.00	$35.56	$34.85	$0.31	$0.40
PECO	$55.19	$49.47	$3.82	$1.90	$36.34	$35.07	$0.46	$0.81
PENELEC	$48.18	$48.27	($0.46)	$0.37	$34.40	$34.22	($0.25)	$0.44
Pepco	$55.71	$49.82	$4.63	$1.26	$39.18	$35.31	$2.95	$0.92
PPL	$53.76	$48.95	$3.85	$0.96	$34.57	$34.59	($0.37)	$0.35
PSEG	$57.16	$49.71	$4.78	$2.67	$36.64	$35.31	$0.09	$1.24
RECO	$53.17	$50.88	($0.15)	$2.44	$36.88	$36.17	($0.43)	$1.15
PJM	$49.48	$49.40	$0.05	$0.03	$35.02	$34.97	$0.04	$0.01

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

	2011 (Jan-Sep)				2012 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.45	$49.53	$4.67	$3.25	$37.05	$34.99	$0.51	$1.54
AEP	$42.90	$48.10	($3.25)	($1.96)	$32.36	$33.84	($0.56)	($0.92)
AP	$47.66	$47.96	($0.16)	($0.15)	$34.01	$33.92	$0.16	($0.07)
ATSI	$46.14	$50.87	($3.07)	($1.66)	$33.09	$34.00	($0.78)	($0.13)
BGE	$57.10	$49.19	$5.16	$2.75	$39.53	$34.62	$3.00	$1.90
ComEd	$38.12	$48.12	($6.46)	($3.55)	$31.08	$34.41	($1.56)	($1.77)
DAY	$43.25	$48.64	($4.21)	($1.18)	$33.46	$34.30	($0.75)	($0.09)
DEOK	NA	NA	NA	NA	$31.87	$34.20	($0.59)	($1.73)
DLCO	$42.60	$48.39	($4.13)	($1.67)	$32.92	$34.13	($0.16)	($1.05)
Dominion	$53.16	$49.11	$3.35	$0.70	$36.40	$34.56	$1.35	$0.49
DPL	$56.97	$49.29	$4.20	$3.48	$38.72	$34.80	$1.85	$2.07
JCPL	$56.24	$49.45	$3.73	$3.06	$36.58	$35.01	$0.24	$1.33
Met-Ed	$52.37	$48.08	$3.28	$1.01	$34.73	$33.96	$0.26	$0.51
PECO	$55.35	$48.61	$4.33	$2.41	$35.96	$34.38	$0.60	$0.98
PENELEC	$47.41	$47.72	($0.56)	$0.24	$33.97	$33.46	($0.00)	$0.51
Pepco	$54.99	$48.72	$4.49	$1.79	$38.14	$34.28	$2.58	$1.28
PPL	$52.82	$48.27	$3.63	$0.93	$34.00	$33.86	($0.19)	$0.33
PSEG	$56.24	$48.89	$4.27	$3.09	$36.66	$34.62	$0.53	$1.51
RECO	$53.55	$49.45	$1.75	$2.35	$36.36	$35.10	$0.02	$1.24
PJM	$48.34	$48.55	($0.05)	($0.16)	$34.29	$34.19	$0.12	($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 cost is based on the day-ahead and real-time energy components of LMP (SMP). Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.[4]

Total Energy Costs

Table 10-5 shows total energy, loss and congestion costs and total PJM billing, for the January through September period of each year from 2009 through 2012. The total energy, loss and congestion costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

4 Net residual adjustments are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

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

(Jan-Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Charges Percent of PJM Billing
2009	($485)	$992	$544	$1,052	$19,927	5.3%
2010	($619)	$1,259	$1,139	$1,780	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%

Energy costs for the first nine 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 nine months of 2009 through 2012 and Table 10-7 shows PJM energy costs by market category for the first nine months of 2009 through 2012. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-5.

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

	Energy Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.6	$28,754.0	$0.0	$7.9	($442.5)

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

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.8)	($99.2)	$0.0	($20.6)	$7.9	($442.5)

Monthly Energy Costs

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

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

	Energy Costs (Millions)							
	2011 (Jan-Sep)				2012 (Jan-Sep)			
	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)	$0.1	($0.3)	($39.6)
Jun	($82.1)	($3.2)	$1.1	($84.2)	($57.1)	$4.0	$0.0	($53.1)
Jul	($110.0)	($16.8)	$6.7	($120.1)	($84.0)	$3.0	$0.6	($80.4)
Aug	($66.9)	($16.4)	$5.0	($78.2)	($60.3)	$2.6	$0.3	($57.4)
Sep	($55.0)	($5.5)	$1.5	($59.0)	($43.6)	$1.1	($0.2)	($42.8)
Total	($622.6)	($55.3)	$26.5	($651.3)	($429.8)	($20.6)	$7.9	($442.5)

Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost 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 marginal loss costs, analogous to total congestion costs, are equal to the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component

5 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.

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.

Monthly marginal loss costs in the first nine months of 2012 ranged from $51.0 million in April to $143.4 million in July.

The marginal loss credits decreased by $188.8 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.3 million in the first nine months of 2012.

Total Marginal Loss Costs

Table 10-9 shows total marginal loss costs for the first nine months for 2009 through 2012. The total energy, loss and congestion costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

Table 10-9 Total[6] PJM Marginal Loss Costs (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-9)

(Jan-Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$992	NA	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%

Total marginal loss costs for the first nine 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 nine months for 2009 through 2012. Table 10-11 shows PJM marginal loss costs by market category for the first nine months for 2009 through 2012.

6 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 September, 2009 through 2012 (See 2011 SOM, Table 10-10)

	Marginal Loss Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($62.5)	($1,028.9)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6

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

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.4	($3.1)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6

Monthly Marginal Loss Costs

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

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

	Marginal Loss Costs (Millions)							
	2011 (Jan - Sep)				2012 (Jan - Sep)			
	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	$92.5
Jul	$217.4	($3.7)	$0.0	$213.7	$141.8	$1.6	$0.0	$143.4
Aug	$137.9	($3.5)	$0.0	$134.5	$96.1	$2.4	$0.0	$98.5
Sep	$107.7	($4.7)	$0.0	$102.9	$71.7	($0.9)	($0.0)	$70.8
Total	$1,191.1	($38.5)	$0.0	$1,152.6	$776.0	($18.5)	$0.0	$757.6

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 costs). These total energy costs are actually net energy costs because they net generation credits and load payments. 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 costs). These total marginal loss costs are actually net marginal loss costs because they net generation credits and loss payments.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. These net costs plus net marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

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

Table 10-13 Marginal[7] loss credits (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-13)

	Loss Credit Accounting (Millions)			
(Jan-Sep)	Total Energy Costs	Total Marginal Loss Costs	Net Residual Adjustments	Loss Credits
2009	($484.6)	$992.4	$0.7	$508.5
2010	($618.6)	$1,259.3	($1.2)	$639.6
2011	($651.3)	$1,152.6	$0.7	$502.1
2012	($442.5)	$757.6	($1.7)	$313.4

7 The net residual adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[8] Total congestion costs are equal to the net congestion bill plus explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

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.[9]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs 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.[10]

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. 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.

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.[11] 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.

8 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

9 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.

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

11 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.

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 nine months of 2012 were $425.2 million, which was comprised of load congestion payments of $116.8 million, negative generation credits of $359.2 million and negative explicit congestion of $50.9 million (Table 10-15).

Total Congestion

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

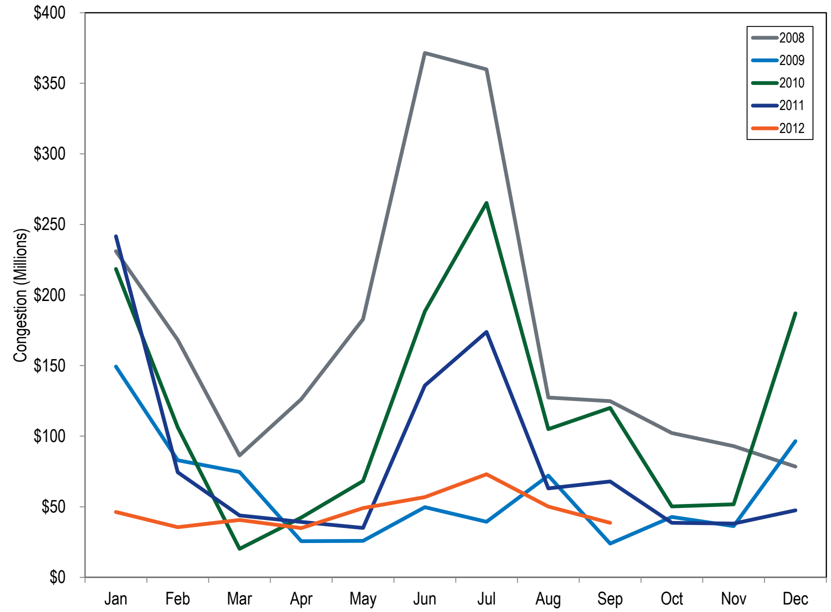
Table 10-14 Total PJM congestion (Dollars (Millions)): January through September for calendar years 2008 to 2012 (See 2011 SOM, Table 10-14)

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979.0	6.6%
2009	$543.6	(69.4%)	$19,927.0	2.7%
2010	$1,134.3	108.7%	$26,249.0	4.3%
2011	$874.9	(22.9%)	$28,836.0	3.0%
2012	$425.2	(51.4%)	$22,119.0	1.9%

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

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

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



Total congestion costs in Table 10-15 include congestion costs 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 nine months of 2012. The January through September 2012 PJM total congestion costs were comprised of $116.8 million in load congestion payments, $359.2 million in negative generation congestion credits, and $50.9 million in negative explicit congestion costs.

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

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2011	$142.1	($835.5)	($102.8)	$0.0	$874.9
2012	$116.8	($359.2)	($50.9)	$0.0	$425.2

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

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2011	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$0.0	$874.9
2012	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

Monthly Congestion

Table 10-17 shows that during the first nine months of 2012, monthly congestion costs ranged from $34.9 million to $73.1 million. Table 10-18 shows the congestion costs during the first nine 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 costs (Dollars (Millions)): January through September 2012 (See 2011 SOM, Table 10-17)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	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	($1.6)	$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)	$16.7	$67.2	$0.5	($2.6)	($21.2)	($18.2)	$0.0	$49.1
Jun	$14.0	($50.9)	$4.7	$69.6	$5.4	$8.3	($9.8)	($12.7)	$0.0	$56.8
Jul	$13.9	($67.6)	$9.5	$91.0	$3.3	$7.3	($13.9)	($17.9)	$0.0	$73.1
Aug	$23.9	($30.0)	$6.9	$60.8	$5.9	$6.9	($9.6)	($10.6)	$0.0	$50.2
Sep	$12.8	($44.0)	$4.9	$61.8	($3.9)	$6.9	($12.3)	($23.1)	$0.0	$38.7
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

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

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	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
Jul	$3.8	($184.1)	$6.5	$194.4	$21.2	$21.6	($20.2)	($20.6)	$0.0	$173.8
Aug	$4.7	($63.7)	$6.6	$75.0	($0.4)	$1.8	($9.7)	($11.9)	$0.0	$63.1
Sep	$0.0	($84.9)	$6.9	$91.9	$8.8	$21.2	($11.5)	($23.9)	$0.0	$67.9
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$0.0	$874.9

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 nine months of 2012, there were 168,689 day-ahead, congestion-event hours compared to 102,714 day-ahead, congestion-event hours in the first nine months of 2011. In the first nine months of 2012, there were 15,254 real-time, congestion-event hours compared to 16,536 real-time, congestion-event hours in the first nine months of 2011.

During the first nine 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 nine months of 2012, for 39.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South interface was the largest contributor to congestion costs in the first nine months of 2012. With $50.9 million in total congestion costs, it accounted for 12.0 percent of the total PJM congestion costs in the first nine months of 2012. The top five constraints in terms of congestion costs together contributed $112.5 million, or 26.5 percent, of the total PJM congestion costs in the first nine months of 2012. The top five constraints were the AP South interface, Graceton – Raphael Road transmission line, Woodstock flowgate, Belvidere – Woodstock line and Clover transformer.

Congestion by Facility Type and Voltage

In the first nine months of 2012, compared to the first nine 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 nine months of 2012 compared to the first nine months of 2011 and decreased on PJM interfaces, transmission lines and transformers in the first nine months of 2012 compared to the first nine 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 nine months of 2012 compared to first nine months of 2011.

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

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

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($42.8)	($145.9)	$28.5	$131.5	($4.4)	$7.5	($66.6)	($78.5)	$53.0	21,819	5,355
Interface	$48.5	($51.1)	$0.0	$99.6	$12.8	$15.5	($3.3)	($6.1)	$93.6	4,451	421
Line	$66.1	($155.4)	$41.0	$262.4	($8.4)	$18.2	($54.9)	($81.5)	$180.9	101,021	7,686
Other	$9.5	($4.0)	$1.1	$14.6	($0.6)	$0.0	($0.9)	($1.5)	$13.0	3,871	428
Transformer	$29.1	($45.6)	$14.3	$89.0	$4.1	$2.7	($11.6)	($10.1)	$78.9	37,527	1,364
Unclassified	$2.8	($1.3)	$1.8	$6.0	$0.2	$0.2	($0.2)	($0.3)	$5.7	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,689	15,254

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

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($67.9)	($132.2)	$9.5	$73.8	$7.4	$10.8	($58.1)	($61.5)	$12.2	15,070	4,226
Interface	$55.9	($375.4)	($12.4)	$418.9	$36.9	$37.1	$8.9	$8.7	$427.6	7,068	1,598
Line	$45.9	($276.0)	$25.1	$347.1	$23.5	$48.0	($59.2)	($83.7)	$263.4	58,823	7,291
Other	($1.0)	($4.5)	$0.6	$4.0	$2.1	$4.5	($0.2)	($2.7)	$1.4	622	145
Transformer	$34.5	($159.4)	$17.8	$211.7	$3.2	$13.1	($38.5)	($48.4)	$163.3	21,131	3,276
Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	NA	NA
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$874.9	102,714	16,536

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 nine months of 2012, there were 168,689 congestion event hours in the Day-Ahead Market. Among those, only 6,196 (3.7 percent) were also constrained in the Real-Time Market. In the first nine months of 2011, among the 102,714 day-ahead congestion event hours, only 6,720 (6.5 percent) were binding in the Real-Time Market.[16]

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 nine months of 2012, there 15,254 congestion event hours in the Real-Time Market. Among these, 6,081 (39.9 percent) were also constrained in the Day-Ahead Market. In the first nine months of 2011, among the 16,536 real-time congestion event hours, only 6,600 (40.3 percent) were binding in the day-ahead.

14 The term flowgate refers to MISO flowgates in this section.

15 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.

16 Constraints are mapped to transmission facilities. In the Day-Ahead Market, within a given hour, a single facility may be associated with multiple 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.

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

	Congestion Event Hours					
	2012 (Jan - Sep)			2011 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,819	2,493	11.4%	15,070	1,861	12.3%
Interface	4,451	167	3.8%	7,068	1,018	14.4%
Line	101,021	2,682	2.7%	58,823	2,364	4.0%
Other	3,871	265	6.8%	622	2	0.3%
Transformer	37,527	589	1.6%	21,131	1,475	7.0%
Total	168,689	6,196	3.7%	102,714	6,720	6.5%

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

	Congestion Event Hours					
	2012 (Jan - Sep)			2011 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,355	2,569	48.0%	4,226	1,867	44.2%
Interface	421	165	39.2%	1,598	1,017	63.6%
Line	7,686	2,554	33.2%	7,291	2,329	31.9%
Other	428	229	53.5%	145	2	1.4%
Transformer	1,364	564	41.3%	3,276	1,445	44.1%
Total	15,254	6,081	39.9%	16,536	6,660	40.3%

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

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

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($2.8)	$2.6	$5.3	$0.2	($0.1)	($0.1)	$0.1	$5.4	2,256	89
500	$51.6	($59.8)	$1.9	$113.3	$14.1	$15.2	($5.8)	($6.9)	$106.4	8,040	686
345	($33.5)	($103.3)	$14.1	$84.0	$1.0	$6.1	($30.1)	($35.2)	$48.9	22,915	2,231
230	$62.8	($61.0)	$12.4	$136.1	$5.6	$5.9	($22.0)	($22.2)	$113.9	25,368	3,276
161	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.7)	($11.9)	($0.8)	3,012	1,189
138	($2.3)	($159.3)	$46.5	$203.4	($6.8)	$11.5	($69.1)	($87.3)	$116.1	87,865	6,281
115	$21.1	($2.2)	$2.6	$25.9	($0.4)	$1.5	($1.1)	($3.0)	$22.9	13,130	738
69	$22.0	$4.4	$0.3	$18.0	($9.5)	$2.3	$0.5	($11.3)	$6.6	6,091	762
34	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	2
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
Unclassified	$2.8	($1.4)	$1.9	$6.1	$0.2	$0.2	($0.2)	($0.3)	$5.8	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,689	15,254

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

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$0.8	($8.7)	$2.0	$11.5	$2.8	$2.0	($2.4)	($1.6)	$9.9	830	139
500	$90.7	($440.7)	($7.5)	$523.8	$41.3	$45.6	($9.0)	($13.3)	$510.5	14,985	3,339
345	($64.9)	($184.5)	$10.7	$130.3	$7.4	$20.5	($54.0)	($67.1)	$63.2	17,547	2,704
230	($8.1)	($162.1)	$11.4	$165.4	$18.5	$19.0	($32.5)	($32.9)	$132.4	17,050	2,600
161	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	1,098	651
138	$35.0	($122.7)	$16.7	$174.4	$4.3	$14.4	($35.0)	($45.0)	$129.4	36,790	5,830
115	$9.1	($14.5)	$3.0	$26.6	$1.8	$6.7	($1.2)	($6.1)	$20.5	7,789	738
69	$13.4	($1.2)	($0.2)	$14.4	($2.0)	$2.0	$0.0	($4.0)	$10.4	6,599	530
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	5
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	17	0
Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	NA	NA
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$874.9	102,697	16,536

Constraint Duration

Table 10-25 lists constraints in the first nine 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 nine months of 2011 to the first nine months of 2012.

Table 10-25 Top 25 constraints with frequent occurrence: January through September 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	11,131	11,131	0	0	0	0%	127%	127%	0%	0%	0%
2	Oak Grove - Galesburg	Flowgate	1,098	3,012	1,914	651	1,182	531	13%	34%	22%	7%	13%	6%
3	Kammer	Transformer	260	3,285	3,025	47	13	(34)	3%	37%	34%	1%	0%	(0%)
4	Graceton - Raphael Road	Line	218	2,478	2,260	103	693	590	2%	28%	26%	1%	8%	7%
5	Monticello - East Winamac	Flowgate	482	2,544	2,062	120	567	447	6%	29%	23%	1%	6%	5%
6	Linden - VFT	Line	1,813	3,007	1,194	0	0	0	21%	34%	14%	0%	0%	0%
7	Huntingdon - Huntingdon1	Line	0	2,786	2,786	0	0	0	0%	32%	32%	0%	0%	0%
8	Cumberland - Bush	Flowgate	914	2,053	1,139	159	313	154	10%	23%	13%	2%	4%	2%
9	Big Sandy - Grangston	Line	29	2,218	2,189	0	0	0	0%	25%	25%	0%	0%	0%
10	Crete - St Johns Tap	Flowgate	2,763	1,910	(853)	640	277	(363)	32%	22%	(10%)	7%	3%	(4%)
11	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
12	Clover	Transformer	1,193	1,564	371	460	441	(19)	14%	18%	4%	5%	5%	(0%)
13	Howard - Shelby	Line	196	1,991	1,795	0	0	0	2%	23%	20%	0%	0%	0%
14	Dixon - Stillman Valley	Line	125	1,854	1,729	60	81	21	1%	21%	20%	1%	1%	0%
15	AP South	Interface	3,334	1,725	(1,609)	861	157	(704)	38%	20%	(18%)	10%	2%	(8%)
16	Taylor - Grenshaw	Line	0	1,831	1,831	0	0	0	0%	21%	21%	0%	0%	0%
17	Nelson - Cordova	Line	425	1,563	1,138	84	253	169	5%	18%	13%	1%	3%	2%
18	Belmont	Transformer	3,838	1,737	(2,101)	497	60	(437)	44%	20%	(24%)	6%	1%	(5%)
19	Conesville	Transformer	0	1,750	1,750	0	0	0	0%	20%	20%	0%	0%	0%
20	Wolfcreek	Transformer	2,148	1,611	(537)	226	49	(177)	25%	18%	(6%)	3%	1%	(2%)
21	Conesville	Transformer	0	1,594	1,594	0	0	0	0%	18%	18%	0%	0%	0%
22	Hillsdale - New Milford	Line	0	1,331	1,331	4	259	255	0%	15%	15%	0%	3%	3%
23	Bellefonte - Grangston	Line	12	1,577	1,565	0	0	0	0%	18%	18%	0%	0%	0%
24	Danville - East Danville	Line	3,297	1,570	(1,727)	321	6	(315)	38%	18%	(20%)	4%	0%	(4%)
25	Bayway - Federal Square	Line	777	1,503	726	15	48	33	9%	17%	8%	0%	1%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through September 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	11,131	11,131	0	0	0	0%	127%	127%	0%	0%	0%
2	South Mahwah - Waldwick	Line	4,628	88	(4,540)	473	0	(473)	53%	1%	(52%)	5%	0%	(5%)
3	Kammer	Transformer	260	3,285	3,025	47	13	(34)	3%	37%	34%	1%	0%	(0%)
4	Graceton - Raphael Road	Line	218	2,478	2,260	103	693	590	2%	28%	26%	1%	8%	7%
5	Huntingdon - Huntingdon1	Line	0	2,786	2,786	0	0	0	0%	32%	32%	0%	0%	0%
6	Belmont	Transformer	3,838	1,737	(2,101)	497	60	(437)	44%	20%	(24%)	6%	1%	(5%)
7	Monticello - East Winamac	Flowgate	482	2,544	2,062	120	567	447	6%	29%	23%	1%	6%	5%
8	Oak Grove - Galesburg	Flowgate	1,098	3,012	1,914	651	1,182	531	13%	34%	22%	7%	13%	6%
9	AP South	Interface	3,334	1,725	(1,609)	861	157	(704)	38%	20%	(18%)	10%	2%	(8%)
10	Fairview	Transformer	2,248	0	(2,248)	0	0	0	26%	0%	(26%)	0%	0%	0%
11	Big Sandy - Grangston	Line	29	2,218	2,189	0	0	0	0%	25%	25%	0%	0%	0%
12	Cox's Corner - Marlton	Line	2,618	468	(2,150)	0	0	0	30%	5%	(25%)	0%	0%	0%
13	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
14	Danville - East Danville	Line	3,297	1,570	(1,727)	321	6	(315)	38%	18%	(20%)	4%	0%	(4%)
15	Michigan City - Laporte	Flowgate	2,323	866	(1,457)	571	40	(531)	27%	10%	(17%)	7%	0%	(6%)
16	Electric Jct - Nelson	Line	2,303	621	(1,682)	158	5	(153)	26%	7%	(19%)	2%	0%	(2%)
17	Taylor - Grenshaw	Line	0	1,831	1,831	0	0	0	0%	21%	21%	0%	0%	0%
18	Howard - Shelby	Line	196	1,991	1,795	0	0	0	2%	23%	20%	0%	0%	0%
19	Dixon - Stillman Valley	Line	125	1,854	1,729	60	81	21	1%	21%	20%	1%	1%	0%
20	Conesville	Transformer	0	1,750	1,750	0	0	0	0%	20%	20%	0%	0%	0%
21	East Frankfort - Crete	Line	1,403	1	(1,402)	313	0	(313)	16%	0%	(16%)	4%	0%	(4%)
22	Wylie Ridge	Transformer	1,882	572	(1,310)	357	4	(353)	21%	7%	(15%)	4%	0%	(4%)
23	Pinehill - Stratford	Line	1,888	288	(1,600)	0	0	0	22%	3%	(18%)	0%	0%	0%
24	Conesville	Transformer	0	1,594	1,594	0	0	0	0%	18%	18%	0%	0%	0%
25	Hillsdale - New Milford	Line	0	1,331	1,331	4	259	255	0%	15%	15%	0%	3%	3%

Constraint Costs

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

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

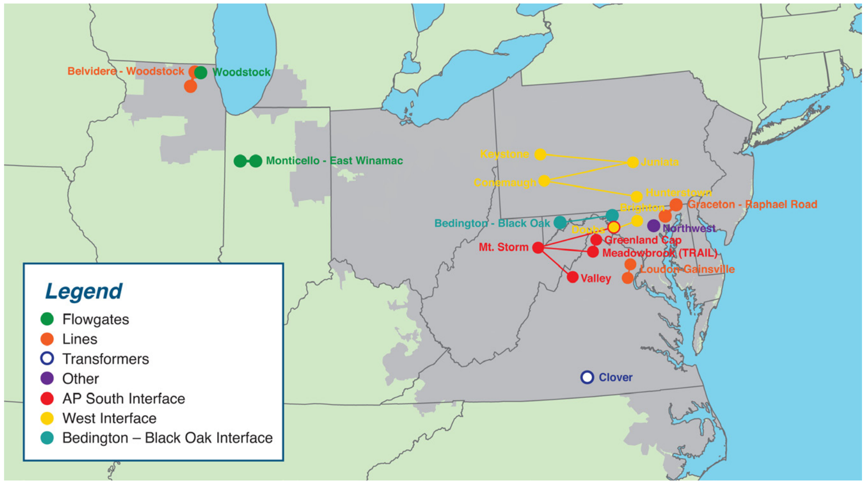
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012 (Jan - Sep)
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	12%
2	Graceton - Raphael Road	Line	BGE	$25.1	($7.8)	($1.6)	$31.3	$0.8	($1.1)	$0.2	$2.1	$33.4	8%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	7%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.7)	$0.9	$5.4	($2.4)	$3.2	($16.8)	($22.5)	($17.1)	(4%)
5	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.7	($8.4)	($8.2)	$15.3	4%
6	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	4%
7	Monticello - East Winamac	Flowgate	MISO	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	3%
8	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	3%
9	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.2	$0.6	$0.9	$0.2	($0.1)	$10.0	2%
10	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	2%
11	Nelson - Cordova	Line	ComEd	($16.6)	($29.5)	$5.8	$18.7	($0.9)	$1.6	($7.5)	($10.0)	$8.7	2%
12	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.8	$0.1	$0.0	($0.0)	$0.0	$7.8	2%
13	Pleasant Valley - Belvidere	Line	ComEd	($2.2)	($8.0)	$1.8	$7.6	$0.1	$0.1	($0.8)	($0.7)	$6.9	2%
14	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.3)	$6.9	($0.2)	$0.1	$0.2	($0.0)	$6.9	2%
15	Unclassified	Unclassified	Unclassified	$2.8	($1.3)	$1.8	$6.0	$0.2	$0.2	($0.2)	($0.3)	$5.7	1%
16	AEP-DOM	Interface	500	$6.0	($2.0)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.2	1%
17	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1%
18	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1%
19	Plymouth Meeting - Whitpain	Line	PECO	$0.8	($3.9)	($0.1)	$4.6	$0.3	$0.7	$0.5	$0.0	$4.7	1%
20	Electric Jct - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	1%
21	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1%
22	Buxmont - Whitpain	Line	PPL	($1.1)	($6.9)	($1.5)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1%
23	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	1%
24	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	1%
25	Kenova - Tri State	Line	AEP	$0.4	($3.4)	($0.1)	$3.8	($0.0)	$0.1	$0.1	$0.0	$3.8	1%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September 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 Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2011 (Jan - Sep)
1	AP South	Interface	500	$87.4	($133.0)	($1.4)	$219.0	$17.9	$15.8	$1.9	$4.0	$223.1	25%
2	5004/5005 Interface	Interface	500	($24.7)	($96.7)	($4.7)	$67.4	$16.2	$18.3	$7.4	$5.2	$72.6	8%
3	West	Interface	500	($19.3)	($82.1)	($5.2)	$57.6	$0.2	$0.1	$0.1	$0.3	$57.8	7%
4	Belmont	Transformer	AP	$7.9	($48.7)	($2.3)	$54.3	($3.5)	($3.2)	($1.6)	($1.8)	$52.5	6%
5	AEP-DOM	Interface	500	$13.3	($19.3)	$2.0	$34.6	$1.9	$1.5	($0.3)	$0.1	$34.7	4%
6	Electric Jct - Nelson	Line	ComEd	($9.9)	($40.6)	$6.8	$37.6	$0.4	$3.7	($7.7)	($11.0)	$26.6	3%
7	Bedington - Black Oak	Interface	500	$10.6	($14.3)	($2.0)	$22.9	$0.2	$0.1	$0.0	$0.1	$23.1	3%
8	Crete - St Johns Tap	Flowgate	MISO	($27.7)	($53.3)	($4.0)	$21.7	$5.3	$4.4	($2.1)	($1.2)	$20.5	2%
9	Clover	Transformer	Dominion	$0.4	($21.3)	$4.5	$26.2	$2.8	$3.5	($7.6)	($8.3)	$17.9	2%
10	Dickerson - Quince Orchard	Line	Pepco	($9.4)	($28.8)	($1.7)	$17.7	$4.6	$7.4	$2.7	($0.2)	$17.5	2%
11	East	Interface	500	($10.1)	($27.5)	($1.1)	$16.2	$0.2	$1.3	$0.1	($1.0)	$15.3	2%
12	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	2%
13	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.6	$2.2	$1.2	($2.5)	($1.5)	$12.1	1%
14	East Frankfort - Crete	Line	ComEd	($9.2)	($21.9)	($1.3)	$11.4	$0.6	$0.7	($0.5)	($0.6)	$10.8	1%
15	Brues - West Bellaire	Line	AEP	$19.5	$4.9	$0.6	$15.2	($1.9)	$1.7	($1.3)	($4.9)	$10.4	1%
16	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($10.0)	(1%)
17	Plymouth Meeting - Whitpain	Line	PECO	($0.9)	($10.8)	($0.0)	$9.9	$0.2	$0.2	($0.1)	($0.2)	$9.7	1%
18	Cloverdale	Transformer	AEP	$0.5	($7.5)	$1.6	$9.6	$0.7	$0.6	($0.1)	($0.0)	$9.6	1%
19	Oak Grove - Galesburg	Flowgate	MISO	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	(1%)
20	Bunsonville - Eugene	Flowgate	MISO	($8.3)	($14.6)	$1.5	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	1%
21	Unclassified	Unclassified	Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	1%
22	Pleasant Valley - Belvidere	Line	ComEd	($6.5)	($17.0)	$1.7	$12.3	($0.6)	$2.1	($3.0)	($5.7)	$6.5	1%
23	Cloverdale - Lexington	Line	500	$4.8	($2.9)	$1.2	$9.0	$3.3	$2.1	($3.8)	($2.7)	$6.3	1%
24	Gore - Hampshire	Line	AP	$0.0	($6.3)	($0.3)	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	1%
25	Danville - East Danville	Line	AEP	$25.1	$16.4	($2.7)	$5.9	$1.7	$1.2	($0.7)	($0.2)	$5.7	1%

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

Figure 10-2 Location of the top 10 constraints affecting PJM congestion costs: January through September 2012[17] (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 nine 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 nine 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.

17 The term flowgate refers to MISO reciprocal coordinated flowgates in this section.
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 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2012 (See 2011 SOM, Table 10-29)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	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	567
2	Monticello - East Winamac	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	2,544	567
3	Palisades - Roosevelt	($0.8)	($5.1)	($0.6)	$3.7	$0.1	$0.3	($0.2)	($0.4)	$3.3	739	209
4	Crete - St Johns Tap	($4.9)	($15.5)	($1.3)	$9.3	$0.3	$0.9	($5.7)	($6.3)	$3.0	1,910	277
5	Breed - Wheatland	($1.3)	($8.2)	($0.1)	$6.9	$0.3	$0.3	($9.6)	($9.6)	($2.8)	1,252	276
6	Miami Fort - Hebron	($1.4)	($4.2)	($0.2)	$2.6	($0.1)	($0.0)	$0.1	$0.0	$2.6	685	76
7	Benton Harbor - Palisades	($0.4)	($3.5)	($0.8)	$2.4	$0.1	$0.3	($0.2)	($0.4)	$2.0	506	71
8	Rising	($0.3)	($0.3)	$0.0	$0.1	($0.4)	$0.2	($1.1)	($1.6)	($1.5)	48	114
9	Prairie State - W Mt. Vernon	($1.8)	($2.8)	$0.5	$1.5	($0.0)	$0.0	($0.2)	($0.2)	$1.3	495	186
10	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($10.9)	($11.7)	($1.2)	2,053	313
11	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.1	$0.0	($0.1)	($0.2)	($0.1)	$1.0	224	59
12	Rantoul - Rantoul Jct	($2.3)	($4.8)	$0.3	$2.8	($0.2)	($0.1)	($1.7)	($1.9)	$0.9	1,051	315
13	Oak Grove - Galesburg	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.6)	($11.8)	($0.7)	3,012	1,182
14	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	12
15	Bunsonville - Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	42
16	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	11
17	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	23
18	Michigan City - Laporte	($0.8)	($2.3)	($0.3)	$1.1	($0.3)	($0.1)	($0.3)	($0.5)	$0.6	866	40
19	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
20	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	0

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

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($27.7)	($53.3)	($4.0)	$21.7	$5.3	$4.4	($2.1)	($1.2)	$20.5	2,763	640
2	Oak Grove - Galesburg	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	1,098	651
3	Bunsonville - Eugene	($8.3)	($14.6)	$1.5	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	1,794	0
4	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.2)	($0.1)	($5.7)	($5.8)	($5.5)	24	294
5	Pleasant Prairie - Zion	($1.2)	($2.3)	$2.0	$3.1	($0.1)	($0.5)	($7.9)	($7.5)	($4.4)	839	210
6	Michigan City - Laporte	($9.1)	($14.4)	$2.2	$7.5	($1.4)	($1.1)	($3.2)	($3.6)	$3.9	2,323	571
7	Cook - Palisades	($0.9)	($3.9)	$0.2	$3.2	$0.0	$0.0	($0.2)	($0.2)	$3.0	419	9
8	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$1.1	$1.1	($2.7)	($2.8)	($1.8)	67	120
9	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	($1.5)	($1.8)	($1.8)	0	49
10	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($1.6)	($1.7)	($1.7)	0	76
11	Rising	($5.2)	($8.1)	($0.1)	$2.8	$0.0	$1.1	($3.3)	($4.4)	($1.6)	947	172
12	Rantoul Jct - Sidney	($1.0)	($2.0)	$0.1	$1.1	$0.5	$0.0	($0.2)	$0.3	$1.3	62	113
13	Rantoul - Rantoul Jct	($1.8)	($3.1)	$0.3	$1.6	$0.1	$0.1	($0.4)	($0.4)	$1.2	289	129
14	Burr Oak	$1.0	($0.2)	$0.0	$1.2	$0.3	($0.0)	($0.4)	($0.1)	$1.2	147	27
15	Kenosha - Lakeview	$0.3	($2.4)	$0.8	$3.6	($0.3)	($0.6)	($5.0)	($4.7)	($1.1)	986	349
16	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.4	$0.2	($1.2)	($1.0)	($1.0)	0	16
17	Cooper South	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	($0.6)	($0.8)	($0.8)	0	16
18	Cumberland - Bush	($0.4)	($2.8)	$0.8	$3.1	$0.2	$0.3	($2.4)	($2.4)	$0.7	914	159
19	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.7)	($0.6)	($0.6)	0	27
20	Miami Fort	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	96	5

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 nine 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 September 2012 (See 2011 SOM, Table 10-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	1,725	17
2	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	369	17
3	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	412	54
4	AEP-DOM	Interface	500	$6.0	($2.0)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.2	1,299	59
5	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	190	5
6	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	160	121
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	($0.8)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	184	2
9	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
10	Nagel	Line	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	30	0
11	AEP - DOM	Interface	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	41	0
12	Mount Storm - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
13	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
14	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
15	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 September 2011 (See 2011 SOM, Table 10-32)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$87.4	($133.0)	($1.4)	$219.0	$17.9	$15.8	$1.9	$4.0	$223.1	3,334	861
2	5004/5005 Interface	Interface	500	($24.7)	($96.7)	($4.7)	$67.4	$16.2	$18.3	$7.4	$5.2	$72.6	684	439
3	West	Interface	500	($19.3)	($82.1)	($5.2)	$57.6	$0.2	$0.1	$0.1	$0.3	$57.8	798	19
4	AEP-DOM	Interface	500	$13.3	($19.3)	$2.0	$34.6	$1.9	$1.5	($0.3)	$0.1	$34.7	1,269	172
5	Bedington - Black Oak	Interface	500	$10.6	($14.3)	($2.0)	$22.9	$0.2	$0.1	$0.0	$0.1	$23.1	624	7
6	East	Interface	500	($10.1)	($27.5)	($1.1)	$16.2	$0.2	$1.3	$0.1	($1.0)	$15.3	295	22
7	Cloverdale - Lexington	Line	500	$4.8	($2.9)	$1.2	$9.0	$3.3	$2.1	($3.8)	($2.7)	$6.3	589	427
8	Central	Interface	500	($1.3)	($2.4)	($0.1)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	64	0
9	Mount Storm - Pruntytown	Line	500	$0.1	($0.2)	$0.0	$0.3	$0.2	$0.0	($0.1)	$0.0	$0.3	29	38
10	Doubs - Mount Storm	Line	500	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	9	4
11	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
12	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	$0.0	$0.0	0	38
13	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9

