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 (SMP) or energy component, the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1]

SMP, MLMP and CLMP are products 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 and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. 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 to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[2] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

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 energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the 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.

The components of LMP are the basis for calculating participant and location specific congestion costs and marginal loss costs.[3]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,195.7 million or 234.6 percent, from $509.6 million in the first nine months of 2013 to $1,705.3 million in the first nine months of 2014. Total congestion costs increased because of the cold weather in January 2014, but congestion was also much higher in March 2014 than in March 2013 and congestion was higher in each of the first nine months of 2014 than in the first nine months of 2013 except July.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,163.2 million or 145.1 percent, from $801.4 million in the first nine months of 2013 to $1,964.6 million in the first nine months of 2014.
- **Balancing Congestion.** Balancing congestion costs increased by $32.5 million or 11.1 percent, from -$291.8 million in the first nine months of 2013 to -$259.3 million in the first nine months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2014 ranged from $54.3 million in April to $825.1 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AP South Interface, the West Interface, the Bagley – Graceton line, the Bedington - Black Oak Interface, and the Breed – Wheatland flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

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

3 The total congestion and marginal losses were calculated as of October 18, 2014, and are subject to change, based on continued PJM billing updates.

Market in the first nine months of 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 15 times higher than the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion frequency increased by 25.3 percent from 261,702 congestion event hours in the first nine months of 2013 to 327,824 congestion event hours in the first nine months of 2014.

Real-time congestion frequency increased by 44.0 percent from 14,677 congestion event hours in the first nine months of 2013 to 21,139 congestion event hours in the first nine months of 2014.

- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of congestion facilities. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2014. With $475.3 million in total congestion costs, it accounted for 27.9 percent of the total PJM congestion costs in the first nine months of 2014.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first nine months of 2014. AEP had $410.2 million in total congestion costs, comprised of -$761.1 million in total load congestion payments, -$1,225.6 million in total generation congestion credits and -$54.3 million in explicit congestion costs. The AP South Interface, the West Interface, the Breed – Wheatland, Monticello - East Winamac and the Benton Harbor - Palisades flowgates contributed $286.6 million, or 78.0 percent of the total AEP control cone congestion costs.

- **Ownership.** In the first nine months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first nine months of 2014, financial companies received $196.4 million in congestion credits, an increase of $114.9 million or 141.1 percent compared to the first nine months of 2013. In the first nine months of 2014, physical companies paid $1,901.7 million in congestion charges, an increase of $1,310.7 million or 221.7 percent compared to the first nine months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $446.2 million or 56.0 percent, from $797.0 million in the first nine months of 2013 to $1,243.1 million in the first nine months of 2014. Total marginal loss costs increased because of the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013. Marginal loss costs were lower in July, August, and September of 2014 than in July, August, and September of 2013. The loss component of LMP remained constant, $0.02 in the first nine months of 2013 and $0.02 in the first nine months of 2014. The loss MW in PJM increased 0.2 percent, from 13,218 GWh in the first nine months of 2013 to 13,241 GWh in the first nine months of 2014.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $476.3 million or 54.6 percent, from $871.6 million in the first nine months of 2013 to $1,347.9 million in the first nine months of 2014.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $30.2 million or 40.4 percent, from -$74.6 million in the first nine months of 2013 to -$104.8 million in the first nine months of 2013.

- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first nine months of 2014 increased compared to the first nine months of 2013, by 310.2 percent in January, 114.4 percent in February, 95.4 percent in March, 7.9 percent in April, 0.9 percent in May, and 9.1 percent in June but decreased in July, August, and September. Monthly total marginal loss costs in the first nine months of 2014 ranged from $68.7 million in May to $414.6 million in January.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs plus total marginal loss costs plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[4] The marginal loss credits increased in the first nine months of 2014 by $136.4 million or 51.0 percent, from $267.3 million in the first nine months of 2013, to $404.1 million in the first nine months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $306.7 million or 58.2 percent, from -$527.2 million in the first nine months of 2013 to -$833.9 million in the first nine months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $573.2 million or 95.3 percent, from -$601.3 million in the first nine months of 2013 to -$1,174.5 million in the first nine months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $266.0 million or 339.9 percent, from $78.2 million in the first nine months of 2013 to $344.2 million in the first nine months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2014 ranged from -$272.7 million in January to -$44.6 million in September.

Conclusion

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, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion for the first four months of the 2014 to 2015 planning period. ARR and FTR revenues offset 80.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first four months of the 2014 to 2015 planning period. In the entire 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65 (April 24, 2014), pp 64-66. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first nine months of 2009 to 2014. The load-weighted average real-time LMP increased $18.86 or 47.4 percent from $39.75 in the first nine months of 2013 to $58.60 in the first nine months of 2014. The load-weighted average congestion component decreased $0.04 or 434.1 percent from $0.01 in the first nine months of 2013 to -$0.03 in the first nine months of 2014. The load-weighted average loss component ($0.02) did not change in the first nine months of 2013 from the first nine months of 2014. The load-weighted average energy component increased $18.90 or 47.6 percent from $39.72 in the first nine months of 2013 to $58.61 in the first nine months of 2014.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2014[5]

(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	$35.27	$35.22	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first nine months of 2009 through 2014. The load-weighted average day-ahead LMP increased $19.60 or 49.6 percent from $39.49 in the first nine months of 2013 to $59.08 in the first nine months of 2014. The load-weighted average congestion component increased $0.12 or 82.3 percent from $0.14 in the first nine months of 2013 to $0.26 in the first nine months of 2014. The load-weighted average loss component decreased $0.01 or 9,330.1 percent from $0.00 in the first nine months of 2013 to -$0.01 in the first nine months of 2014. The load-weighted average energy component increased $19.50 or

5 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

49.5 percent from $39.35 in the first nine months of 2013 to $58.84 in the first nine months of 2014.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2014

(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	$34.46	$34.36	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for the first nine months of 2013 and the first nine months of 2014.

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2013 and the first nine months of 2014.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.09	$40.26	$0.03	$1.80	$62.02	$56.38	$3.32	$2.32
AEP	$36.31	$39.25	($1.98)	($0.96)	$51.76	$59.08	($5.85)	($1.48)
AP	$38.52	$39.43	($0.73)	($0.18)	$58.66	$59.87	($1.31)	$0.10
ATSI	$44.63	$39.50	$4.67	$0.46	$52.74	$57.31	($5.17)	$0.59
BGE	$44.55	$40.05	$2.70	$1.80	$75.84	$60.11	$12.96	$2.77
ComEd	$34.01	$39.78	($3.83)	($1.94)	$44.79	$56.53	($8.79)	($2.95)
DAY	$36.91	$39.70	($2.69)	($0.10)	$51.13	$58.60	($7.51)	$0.04
DEOK	$35.02	$39.62	($2.65)	($1.95)	$48.45	$58.19	($6.89)	($2.84)
DLCO	$36.44	$39.58	($1.85)	($1.29)	$47.04	$56.99	($8.05)	($1.90)
Dominion	$41.77	$39.92	$1.56	$0.29	$70.61	$60.39	$9.72	$0.50
DPL	$43.13	$40.03	$1.10	$2.00	$72.28	$60.55	$8.10	$3.63
EKPC	$35.06	$41.33	($3.93)	($2.35)	$52.51	$63.99	($8.51)	($2.98)
JCPL	$44.45	$40.77	$1.79	$1.89	$62.59	$57.11	$3.05	$2.43
Met-Ed	$40.70	$39.68	$0.24	$0.78	$63.19	$58.96	$2.88	$1.35
PECO	$40.44	$39.84	($0.48)	$1.09	$62.83	$57.98	$3.18	$1.67
PENELEC	$39.51	$39.15	($0.24)	$0.59	$57.50	$58.34	($1.44)	$0.60
Pepco	$43.72	$40.06	$2.47	$1.19	$73.53	$59.33	$12.38	$1.82
PPL	$40.19	$39.46	$0.05	$0.68	$64.58	$59.94	$3.49	$1.15
PSEG	$45.47	$40.04	$3.73	$1.70	$64.49	$56.21	$5.92	$2.36
RECO	$47.74	$40.89	$5.20	$1.65	$62.69	$55.94	$4.54	$2.20
PJM	$39.75	$39.72	$0.01	$0.02	$58.60	$58.61	($0.03)	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.18	$39.88	$0.54	$1.75	$63.56	$56.11	$5.52	$1.93
AEP	$36.92	$39.09	($1.26)	($0.91)	$52.87	$60.29	($6.12)	($1.29)
AP	$38.47	$39.09	($0.40)	($0.23)	$57.95	$60.17	($1.97)	($0.25)
ATSI	$38.50	$39.24	($0.98)	$0.24	$53.70	$57.89	($4.67)	$0.48
BGE	$44.82	$39.72	$3.39	$1.71	$76.47	$60.15	$14.14	$2.18
ComEd	$34.84	$39.53	($2.93)	($1.76)	$46.11	$57.54	($9.48)	($1.96)
DAY	$37.65	$39.48	($1.65)	($0.18)	$53.02	$59.70	($6.96)	$0.29
DEOK	$35.94	$39.24	($1.60)	($1.70)	$49.74	$57.82	($5.96)	($2.13)
DLCO	$36.67	$39.33	($1.37)	($1.29)	$47.80	$57.31	($7.41)	($2.09)
Dominion	$42.02	$39.71	$2.15	$0.16	$67.02	$60.45	$6.64	($0.07)
DPL	$43.19	$39.65	$1.57	$1.97	$74.07	$60.20	$10.81	$3.07
EKPC	$36.83	$41.03	($1.92)	($2.28)	$53.54	$64.49	($8.12)	($2.83)
JCPL	$43.63	$40.13	$1.71	$1.78	$66.58	$57.84	$6.40	$2.35
Met-Ed	$40.57	$39.12	$0.82	$0.63	$64.69	$58.49	$5.31	$0.90
PECO	$40.71	$39.41	$0.28	$1.02	$64.75	$57.90	$5.46	$1.39
PENELEC	$39.56	$38.57	$0.27	$0.72	$56.74	$56.40	($0.29)	$0.63
Pepco	$43.51	$39.20	$3.17	$1.13	$71.65	$58.37	$11.94	$1.34
PPL	$40.12	$39.04	$0.56	$0.52	$67.02	$59.95	$6.35	$0.73
PSEG	$45.51	$39.79	$3.98	$1.75	$68.95	$57.02	$9.62	$2.31
RECO	$46.59	$40.03	$4.92	$1.64	$66.39	$56.24	$7.99	$2.16
PJM	$39.49	$39.35	$0.14	($0.00)	$59.08	$58.84	$0.26	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first nine months of 2013 and the first nine months of 2014.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.11	$38.92	($2.61)	($2.20)	$46.05	$57.98	($8.19)	($3.74)
AEP-DAY Hub	$35.96	$39.22	($2.20)	($1.06)	$49.43	$58.55	($7.41)	($1.71)
ATSI Gen Hub	$42.82	$38.66	$4.31	($0.15)	$51.19	$57.24	($5.74)	($0.32)
Chicago Gen Hub	$32.26	$38.87	($4.16)	($2.44)	$42.40	$55.59	($9.49)	($3.70)
Chicago Hub	$34.55	$40.25	($3.81)	($1.88)	$45.47	$57.23	($8.87)	($2.89)
Dominion Hub	$42.06	$40.80	$1.42	($0.16)	$72.01	$62.67	$9.52	($0.17)
Eastern Hub	$42.08	$38.93	$1.13	$2.01	$66.76	$57.17	$6.33	$3.26
N Illinois Hub	$33.36	$39.30	($3.83)	($2.10)	$43.90	$56.24	($9.09)	($3.25)
New Jersey Hub	$44.73	$40.34	$2.65	$1.74	$62.61	$55.97	$4.33	$2.31
Ohio Hub	$36.07	$39.45	($2.43)	($0.96)	$49.53	$58.47	($7.39)	($1.54)
West Interface Hub	$38.47	$38.48	$0.59	($0.60)	$54.38	$55.82	($0.51)	($0.93)
Western Hub	$41.19	$40.63	$0.44	$0.12	$63.04	$60.30	$2.70	$0.04

The day-ahead components of LMP for each hub are presented in Table 11-6 for the first nine months of 2013 and the first nine months of 2014.

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for the first nine months of 2009 through 2014. These totals are actually net energy, loss and congestion costs.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January through September of 2009 through 2014[6][7]

	Component Costs (Millions)					
(Jan - Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($485)	$992	$544	$1,051	$19,927	5.3%
2010	($619)	$1,259	$1,134	$1,775	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%
2013	($527)	$797	$510	$779	$25,153	3.1%
2014	($834)	$1,243	$1,705	$2,114	$40,760	5.2%

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.91	$37.47	($1.65)	($1.92)	$42.38	$49.27	($4.36)	($2.53)
AEP-DAY Hub	$35.99	$38.19	($1.25)	($0.94)	$48.65	$55.47	($5.75)	($1.07)
ATSI Gen Hub	$35.74	$36.52	($0.68)	($0.10)	$50.89	$53.43	($2.67)	$0.13
Chicago Gen Hub	$32.89	$38.16	($3.14)	($2.12)	$43.99	$57.58	($10.76)	($2.82)
Chicago Hub	$33.93	$38.32	($2.76)	($1.63)	$44.51	$55.14	($8.89)	($1.73)
Dominion Hub	$41.62	$39.75	$2.08	($0.21)	$65.27	$59.98	$6.00	($0.71)
Eastern Hub	$43.13	$39.35	$1.63	$2.16	$69.51	$57.58	$8.86	$3.07
N Illinois Hub	$33.76	$38.58	($2.95)	($1.86)	$44.51	$56.28	($9.56)	($2.21)
New Jersey Hub	$44.06	$39.57	$2.79	$1.70	$65.19	$55.87	$7.17	$2.14
Ohio Hub	$36.27	$38.34	($1.24)	($0.83)	$49.03	$55.84	($5.97)	($0.84)
West Interface Hub	$41.37	$41.82	$0.06	($0.51)	$50.50	$51.35	($0.10)	($0.76)
Western Hub	$40.19	$38.84	$1.16	$0.19	$57.35	$54.79	$2.68	($0.12)

6 The energy costs, loss costs and congestion costs include net inadvertent charges.
7 Total PJM billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[8] Total congestion costs are equal to the net implicit congestion bill plus net 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]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

Total congestion costs in PJM in the first nine months of 2014 were $1,705.3 million, which was comprised of load congestion payments of $578.4 million, generation credits of -$1,273.4 million and explicit congestion of -$146.5 million (Table 11-9).

Total Congestion

Table 11-8 shows total congestion for the first nine months of 2008 through 2014.

Table 11-8 Total PJM congestion (Dollars (Millions)): January through September of 2008 through 2014

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979	6.6%
2009	$543.6	(69.4%)	$19,927	2.7%
2010	$1,134.3	108.7%	$26,249	4.3%
2011	$874.9	(22.9%)	$28,836	3.0%
2012	$425.2	(51.4%)	$22,119	1.9%
2013	$509.6	19.9%	$25,153	2.0%
2014	$1,705.3	234.6%	$40,760	4.2%

Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[10] [11]

Table 11-9 shows the congestion costs by accounting category for the first nine months of 2014. In the first nine months of 2014, PJM total congestion costs were comprised of $578.4 million in load congestion payments, -$1,273.4 million in generation congestion credits, and -$146.5 million in explicit congestion costs.

Table 11-9 Total PJM congestion costs by accounting category (Dollars (Millions)): January through September of 2008 through 2014

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$921.9	($880.7)	($24.5)	$0.0	$1,778.2
2009	$210.6	($380.9)	($48.0)	$0.0	$543.6
2010	$290.2	($893.3)	($49.2)	($0.0)	$1,134.3
2011	$442.0	($535.7)	($102.8)	$0.0	$874.9
2012	$103.3	($372.7)	($50.9)	$0.0	$425.2
2013	$234.0	($340.5)	($64.8)	$0.0	$509.6
2014	$578.4	($1,273.4)	($146.5)	$0.0	$1,705.3

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.

10 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 April 17, 2013).

11 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through September of 2008 through 2014

	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
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$0.0	$1,705.3

Monthly Congestion

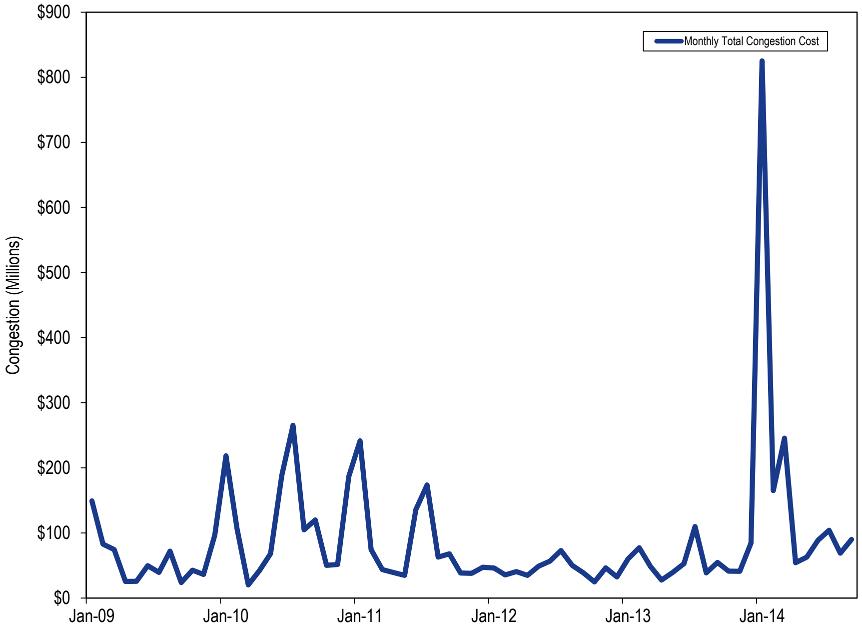
Table 11-11 shows that monthly total congestion costs ranged from $54.3 million to $825.1 million in 2014. Table 11-11 shows that congestions costs in January of 2014 were substantially higher than congestion costs in January of 2013, due to emergency conditions.

Table 11-11 Monthly PJM congestion costs by market (Dollars (Millions)): January through September of 2013 and 2014

	Congestion Costs (Millions)							
	2013 (Jan - Sep)				2014 (Jan - Sep)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$136.8	($76.8)	$0.0	$60.0	$922.5	($97.4)	$0.0	$825.1
Feb	$125.1	($47.7)	$0.0	$77.4	$203.5	($38.3)	$0.0	$165.2
Mar	$69.9	($21.4)	($0.0)	$48.5	$307.3	($61.6)	$0.0	$245.8
Apr	$37.7	($9.9)	$0.0	$27.8	$66.3	($12.0)	($0.0)	$54.3
May	$75.3	($35.8)	($0.0)	$39.5	$84.9	($21.9)	$0.0	$63.1
Jun	$82.2	($29.4)	($0.0)	$52.8	$107.4	($18.6)	$0.0	$88.8
Jul	$131.3	($21.3)	$0.0	$110.1	$118.1	($14.0)	$0.0	$104.1
Aug	$46.0	($7.3)	$0.0	$38.6	$68.9	$0.0	$0.0	$68.9
Sep	$97.0	($42.1)	$0.0	$54.9	$85.8	$4.4	$0.0	$90.1
Total	$801.4	($291.8)	$0.0	$509.6	$1,964.6	($259.3)	$0.0	$1,705.3

Figure 11-1 shows PJM monthly total congestion cost for 2009 through the first nine months of 2014.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through September of 2014



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential 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 usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in 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 consistent with the way in which PJM reports real-time congestion. In the first nine months of 2014, there were 327,824 day-ahead, congestion-event hours compared to 261,702 day-ahead, congestion-event hours in the first nine months of 2013. In the first nine months of 2014, there were 21,139 real-time, congestion-event hours compared to 14,677 real-time, congestion-event hours in the first nine months of 2013.

During the first nine months of 2014, for only 2.8 percent of day-ahead energy market facility constrained hours were the same facilities also constrained in the Real-Time Energy Market. During the first nine months of 2014, for 45.7 percent of real-time energy market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to congestion costs in the first nine months of 2014. With $475.3 million in total congestion costs, it accounted for 27.9 percent of the total PJM congestion costs in the first nine months of 2014. The top five constraints in terms of congestion costs together contributed $893.1 million, or 52.4 percent, of the total PJM congestion costs in the first nine months of 2014. The top five constraints were the AP South Interface, the West Interface, the Bagley - Graceton line, the Bedington - Black Oak Interface, and the Breed – Wheatland flowgate.

Congestion by Facility Type and Voltage

In the first nine months of 2014, compared to the first nine months of 2013, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours increased on all types of facilities.

Day-ahead congestion costs increased on all types of facilities in the first nine months of 2014 compared to the first nine months of 2013. Balancing congestion costs decreased on flowgates, interfaces and transformers and increased on transmission lines in the first nine months of 2014 compared to the first nine months of 2013.

Table 11-12 provides congestion-event hour subtotals and congestion cost subtotals comparing the first nine months of 2014 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[12 13] For comparison, this information is presented in Table 11-13 for the first nine months of 2013.[14]

Table 11-12 Congestion summary (By facility type): January through September of 2014

	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	($90.5)	($373.1)	($15.3)	$267.3	$2.5	$13.9	($37.6)	($49.0)	$218.3	29,993	5,285
Interface	$353.1	($615.8)	($100.9)	$868.0	$62.0	$143.6	$17.0	($64.5)	$803.4	15,935	3,282
Line	$160.1	($410.8)	$36.4	$607.3	($8.2)	$49.8	($46.2)	($104.2)	$503.1	171,951	10,690
Other	$0.2	($1.8)	$1.0	$3.0	$0.0	$0.0	($0.0)	$0.0	$3.0	6,410	1
Transformer	$80.6	($86.1)	$27.3	$194.0	$10.0	$15.7	($49.8)	($55.5)	$138.6	103,535	1,881
Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	NA	NA
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$1,705.3	327,824	21,139

Table 11-13 Congestion summary (By facility type): January through September of 2013

	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	($32.7)	($130.0)	$18.6	$115.9	$0.4	$11.8	($36.0)	($47.4)	$68.5	23,326	4,596
Interface	$142.3	($77.8)	$15.1	$235.2	$22.3	$29.1	($35.2)	($42.0)	$193.2	10,748	1,229
Line	$60.8	($205.9)	$53.9	$320.6	($17.5)	$59.4	($93.7)	($170.7)	$149.9	144,283	7,409
Other	$8.2	($2.0)	$6.6	$16.8	($0.4)	$0.1	($3.0)	($3.5)	$13.3	8,936	121
Transformer	$22.3	($56.1)	$21.3	$99.7	$1.6	$9.6	($19.8)	($27.8)	$71.8	74,409	1,322
Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	NA	NA
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$509.6	261,702	14,677

12 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.
13 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.
14 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 11-14 and Table 11-15 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-14. In the first nine months of 2014, there were 327,824 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 9,183 (2.8 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2013, among the 261,702 day-ahead congestion event hours, only 5,958 (2.3 percent) were binding in the Real-Time Energy Market.[15]

Among the hours for which a facility is constrained in the Real-Time Energy Market, the number of hours during which the facility is also constrained in the Day-Ahead Energy Market are presented in Table 11-15. In the first nine months of 2014, there were 21,139 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 9,665 (45.7 percent) were also constrained in the Day-Ahead Energy Market. In the first nine months of 2013, among the 14,677 real-time congestion event hours, only 6,080 (41.4 percent) were also in the Day-Ahead Energy Market.

Table 11-14 Congestion event hours (Day-Ahead against Real-Time): January through September of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	23,326	1,887	8.1%	29,993	2,981	9.9%
Interface	10,748	910	8.5%	15,935	1,300	8.2%
Line	144,283	2,540	1.8%	171,951	4,335	2.5%
Other	8,936	158	1.8%	6,410	0	0.0%
Transformer	74,409	463	0.6%	103,535	567	0.5%
Total	261,702	5,958	2.3%	327,824	9,183	2.8%

Table 11-15 Congestion event hours (Real-Time against Day-Ahead): January through September of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	4,596	2,022	44.0%	5,285	3,107	58.8%
Interface	1,229	969	78.8%	3,282	1,667	50.8%
Line	7,409	2,535	34.2%	10,690	4,353	40.7%
Other	121	97	80.2%	1	0	0.0%
Transformer	1,322	457	34.6%	1,881	538	28.6%
Total	14,677	6,080	41.4%	21,139	9,665	45.7%

15 Constraints are mapped to transmission facilities. In the Day-Ahead Energy 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 Energy Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-16 shows congestion costs by facility voltage class for the first nine months of 2014. In comparison to the first nine months of 2013 (shown in Table 11-17), congestion costs decreased for facilities rated at 34 kV, 26 kV and 12 kV.

Table 11-16 Congestion summary (By facility voltage): January through September of 2014

	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	$22.7	($38.9)	$3.9	$65.4	$0.5	$1.8	($3.2)	($4.5)	$60.9	11,735	298
500	$364.6	($614.7)	($100.3)	$879.0	$74.0	$159.8	$7.4	($78.4)	$800.5	21,697	2,363
345	($71.2)	($323.3)	$3.0	$255.0	$5.2	$15.3	($28.8)	($38.9)	$216.1	65,481	2,646
230	$109.2	($222.4)	($3.2)	$328.4	$2.6	($2.2)	$2.0	$6.8	$335.2	50,993	5,077
161	($22.6)	($49.3)	($2.8)	$23.9	($1.9)	$0.5	($1.2)	($3.6)	$20.4	5,540	1,054
138	$45.0	($231.7)	$41.6	$318.3	($0.9)	$42.0	($88.3)	($131.2)	$187.1	133,621	7,832
115	$2.8	($18.9)	$4.6	$26.3	($6.1)	$2.7	($3.1)	($11.8)	$14.5	18,157	1,149
69	$53.1	$11.7	$1.6	$43.0	($7.0)	$3.1	($1.4)	($11.5)	$31.6	16,725	720
34	$0.0	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3,853	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	NA	NA
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$1,705.3	327,824	21,139

Table 11-17 Congestion summary (By facility voltage): January through September of 2013

	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	$4.5	($15.7)	$7.6	$27.8	($0.2)	$0.5	$0.8	$0.1	$27.9	7,756	15
500	$141.8	($89.3)	$17.9	$249.0	$27.8	$34.0	($47.0)	($53.2)	$195.7	14,572	1,632
345	($32.7)	($128.1)	$16.0	$111.4	($0.9)	$14.2	($45.4)	($60.5)	$50.9	45,315	3,168
230	$65.4	($114.4)	$38.3	$218.1	($4.5)	$45.5	($48.2)	($98.2)	$119.9	42,424	2,739
161	($4.5)	($9.1)	($0.9)	$3.7	($1.1)	$0.4	($3.0)	($4.5)	($0.8)	1,783	761
138	($14.3)	($119.7)	$33.5	$138.9	($6.2)	$12.4	($41.4)	($60.0)	$79.0	116,029	4,846
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$13.4	($0.1)	$3.1	$16.5	($2.9)	($0.7)	($4.0)	($6.3)	$10.2	13,597	908
69	$21.9	$2.4	($0.9)	$18.6	($5.8)	$3.7	$0.7	($8.8)	$9.8	13,661	579
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	6,007	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	NA	NA
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$509.6	261,702	14,677

Constraint Duration

Table 11-18 lists the constraints in the first nine months of 2013 and the first nine months of 2014 that were most frequently binding and Table 11-19 shows the constraints which experienced the largest change in congestion-event hours from the first nine months of 2013 to the first nine months of 2014.

Table 11-18 Top 25 constraints with frequent occurrence: January through September of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	1,952	8,563	6,611	29	23	(6)	22%	97%	75%	0%	0%	(0%)
2	Tanners Creek	Transformer	4,901	7,752	2,851	0	0	0	56%	88%	32%	0%	0%	0%
3	Braidwood	Transformer	5,710	6,865	1,155	0	0	0	65%	78%	13%	0%	0%	0%
4	Oak Grove - Galesburg	Flowgate	1,451	5,403	3,952	640	938	298	17%	62%	45%	7%	11%	3%
5	Clinch River	Transformer	2,236	6,307	4,071	0	0	0	26%	72%	46%	0%	0%	0%
6	AP South	Interface	4,757	4,685	(72)	915	972	57	54%	53%	(1%)	10%	11%	1%
7	Kendall Co. Energy Ctr.	Transformer	735	5,337	4,602	0	0	0	8%	61%	52%	0%	0%	0%
8	Bagley - Graceton	Line	1,290	3,617	2,327	260	1,381	1,121	15%	41%	26%	3%	16%	13%
9	Wolf Creek	Transformer	773	4,866	4,093	29	129	100	9%	55%	47%	0%	1%	1%
10	Monticello - East Winamac	Flowgate	1,926	3,511	1,585	542	1,440	898	22%	40%	18%	6%	16%	10%
11	Burlington - Croydon	Line	0	4,688	4,688	0	0	0	0%	53%	53%	0%	0%	0%
12	East Bend	Transformer	818	4,613	3,795	0	0	0	9%	53%	43%	0%	0%	0%
13	Mardela - Vienna	Line	2,142	4,441	2,299	199	70	(129)	24%	51%	26%	2%	1%	(1%)
14	Bergen - New Milford	Line	1,355	4,502	3,147	0	0	0	15%	51%	36%	0%	0%	0%
15	Sunbury	Transformer	4,915	4,344	(571)	0	0	0	56%	49%	(7%)	0%	0%	0%
16	Nelson - Cordova	Line	3,919	3,901	(18)	238	268	30	45%	44%	(0%)	3%	3%	0%
17	Gould Street - Westport	Line	6,007	3,803	(2,204)	21	0	(21)	69%	43%	(25%)	0%	0%	(0%)
18	Sporn	Transformer	7,742	3,558	(4,184)	0	0	0	88%	41%	(48%)	0%	0%	0%
19	Huntington Junction - Huntington	Line	2,202	3,375	1,173	0	0	0	25%	38%	13%	0%	0%	0%
20	Breed - Wheatland	Flowgate	1,714	2,810	1,096	293	531	238	20%	32%	12%	3%	6%	3%
21	Howard - Shelby	Line	4,415	3,329	(1,086)	0	0	0	50%	38%	(13%)	0%	0%	0%
22	Fort Robinson - Wolf Hills	Line	734	3,185	2,451	0	0	0	8%	36%	28%	0%	0%	0%
23	Keeney	Transformer	284	3,087	2,803	0	58	58	3%	35%	32%	0%	1%	1%
24	Halifax - Halifax Worsted	Line	2,213	3,061	848	0	1	1	25%	35%	10%	0%	0%	0%
25	Beckjord	Transformer	2,184	3,029	845	0	0	0	25%	34%	10%	0%	0%	0%

Table 11-19 Top 25 constraints with largest year-to-year change in occurrence: January through September of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	1,952	8,563	6,611	29	23	(6)	22%	97%	75%	0%	0%	(0%)
2	Burlington - Croydon	Line	0	4,688	4,688	0	0	0	0%	53%	53%	0%	0%	0%
3	Kendall Co. Energy Ctr.	Transformer	735	5,337	4,602	0	0	0	8%	61%	52%	0%	0%	0%
4	Oak Grove - Galesburg	Flowgate	1,451	5,403	3,952	640	938	298	17%	62%	45%	7%	11%	3%
5	Wolf Creek	Transformer	773	4,866	4,093	29	129	100	9%	55%	47%	0%	1%	1%
6	Sporn	Transformer	7,742	3,558	(4,184)	0	0	0	88%	41%	(48%)	0%	0%	0%
7	Clinch River	Transformer	2,236	6,307	4,071	0	0	0	26%	72%	46%	0%	0%	0%
8	East Bend	Transformer	818	4,613	3,795	0	0	0	9%	53%	43%	0%	0%	0%
9	Bagley - Graceton	Line	1,290	3,617	2,327	260	1,381	1,121	15%	41%	26%	3%	16%	13%
10	Bergen - New Milford	Line	1,355	4,502	3,147	0	0	0	15%	51%	36%	0%	0%	0%
11	Keeney	Transformer	284	3,087	2,803	0	58	58	3%	35%	32%	0%	1%	1%
12	Tanners Creek	Transformer	4,901	7,752	2,851	0	0	0	56%	88%	32%	0%	0%	0%
13	Joshua Falls	Transformer	19	2,853	2,834	0	13	13	0%	32%	32%	0%	0%	0%
14	Cook - Palisades	Flowgate	0	2,316	2,316	0	308	308	0%	26%	26%	0%	4%	4%
15	Haurd - Steward	Line	3,366	749	(2,617)	0	0	0	38%	9%	(30%)	0%	0%	0%
16	Readington - Roseland	Line	3,206	1,169	(2,037)	713	189	(524)	37%	13%	(23%)	8%	2%	(6%)
17	Monticello - East Winamac	Flowgate	1,926	3,511	1,585	542	1,440	898	22%	40%	18%	6%	16%	10%
18	Fort Robinson - Wolf Hills	Line	734	3,185	2,451	0	0	0	8%	36%	28%	0%	0%	0%
19	Sayreville - Sayreville	Line	0	2,394	2,394	0	0	0	0%	27%	27%	0%	0%	0%
20	Bridgewater - Middlesex	Line	2,395	201	(2,194)	230	31	(199)	27%	2%	(25%)	3%	0%	(2%)
21	Gould Street - Westport	Line	6,007	3,803	(2,204)	21	0	(21)	69%	43%	(25%)	0%	0%	(0%)
22	Mardela - Vienna	Line	2,142	4,441	2,299	199	70	(129)	24%	51%	26%	2%	1%	(1%)
23	Zion	Line	2,565	488	(2,077)	0	0	0	29%	6%	(24%)	0%	0%	0%
24	Prairie State - W Mt. Vernon	Flowgate	1,021	0	(1,021)	840	0	(840)	12%	0%	(12%)	10%	0%	(10%)
25	Cloverdale	Transformer	113	1,937	1,824	0	0	0	1%	22%	21%	0%	0%	0%

Constraint Costs

Table 11-20 and Table 11-21 present the top constraints affecting congestion costs by facility for the periods the first nine months of 2014 and the first nine months of 2013.

Table 11-20 Top 25 constraints affecting PJM congestion costs (By facility): January through September of 2014

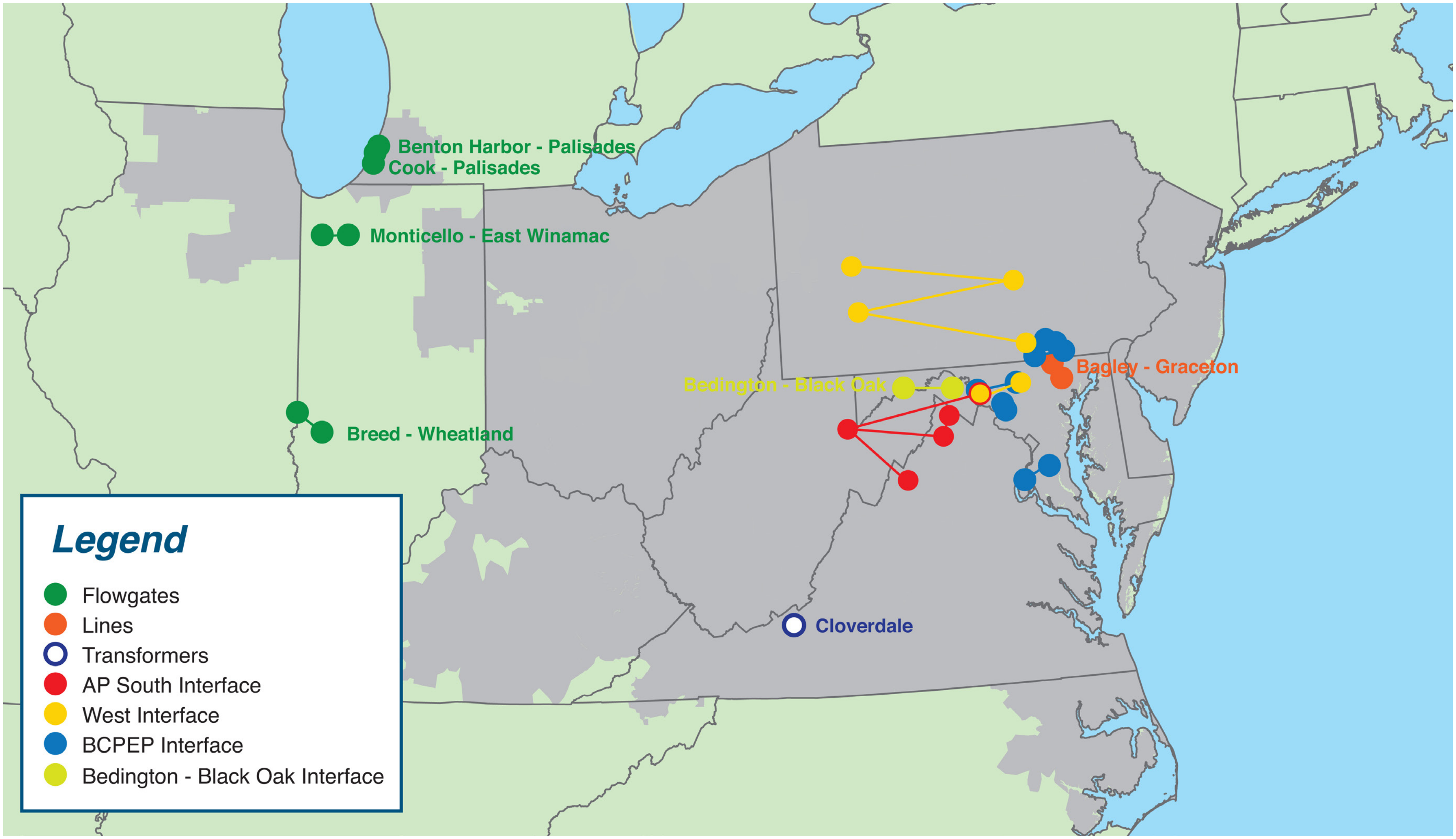
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2014 (Jan - Sep)
1	AP South	Interface	500	$322.0	($196.8)	($10.4)	$508.4	$31.5	$73.5	$8.9	($33.1)	$475.3	27.9%
2	West	Interface	500	($21.3)	($290.9)	($78.6)	$191.0	$16.7	$47.7	$16.8	($14.2)	$176.8	10.4%
3	Bagley - Graceton	Line	BGE	$77.5	($3.8)	($0.9)	$80.4	$4.4	($2.0)	$3.9	$10.3	$90.7	5.3%
4	Bedington - Black Oak	Interface	500	$39.3	($41.0)	$0.2	$80.5	$3.9	$3.5	($2.3)	($1.9)	$78.6	4.6%
5	Breed - Wheatland	Flowgate	MISO	($16.2)	($90.3)	($9.2)	$64.9	$2.3	$1.1	$5.6	$6.8	$71.7	4.2%
6	Cloverdale	Transformer	AEP	$23.0	($27.0)	$0.2	$50.1	$0.0	$0.0	$0.0	$0.0	$50.1	2.9%
7	Benton Harbor - Palisades	Flowgate	MISO	($11.8)	($70.2)	($6.9)	$51.6	($0.2)	$0.7	($1.0)	($1.8)	$49.7	2.9%
8	BCPEP	Interface	Pepco	$13.7	($15.2)	($1.7)	$27.2	($1.6)	($14.2)	$1.5	$14.1	$41.3	2.4%
9	Unclassified	Unclassified	Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	2.3%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.9%
11	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.6%
12	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.5%
13	Cloverdale	Transformer	AEP	$22.3	($4.9)	($2.2)	$25.0	$0.0	$0.0	$0.0	$0.0	$25.0	1.5%
14	Wolf Creek	Transformer	AEP	$4.5	$1.3	$4.6	$7.9	$3.6	$5.6	($29.3)	($31.3)	($23.5)	(1.4%)
15	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.4%
16	Oak Grove - Galesburg	Flowgate	MISO	($22.5)	($48.6)	($2.5)	$23.5	($0.4)	$0.4	$0.1	($0.7)	$22.8	1.3%
17	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.2%
18	East	Interface	500	($9.2)	($32.3)	($3.2)	$19.9	$0.3	$0.7	$0.5	$0.1	$20.0	1.2%
19	Bergen - New Milford	Line	PSEG	$21.3	$12.7	$11.3	$19.9	$0.0	$0.0	$0.0	$0.0	$19.9	1.2%
20	Bridgewater - Middlesex	Line	PSEG	$0.1	($22.1)	($3.0)	$19.2	($1.5)	$0.1	$1.4	($0.2)	$19.0	1.1%
21	Nelson - Cordova	Line	ComEd	($23.5)	($44.4)	$3.9	$24.8	($0.7)	$1.0	($4.2)	($5.9)	$18.9	1.1%
22	5004/5005 Interface	Interface	500	($0.5)	($22.7)	($3.3)	$18.9	$8.1	$17.5	$7.3	($2.2)	$16.7	1.0%
23	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.9%
24	Rising	Flowgate	MISO	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	(0.8%)
25	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	$2.2	$3.9	($10.9)	($12.7)	($12.7)	(0.7%)

Table 11-21 Top 25 constraints affecting PJM congestion costs (By facility): January through September of 2013

				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	2013 (Jan - Sep)
1	AP South	Interface	500	$117.7	($29.5)	$12.9	$160.0	$7.5	$13.3	($9.2)	($15.1)	$144.9	28.4%
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	5.1%
3	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(4.6%)
4	Bridgewater - Middlesex	Line	PSEG	($0.1)	($23.0)	$1.9	$24.8	$1.8	$4.5	($1.8)	($4.4)	$20.4	4.0%
5	Cloverdale	Transformer	AEP	$8.0	($3.6)	$4.9	$16.6	$0.0	$0.0	$0.0	$0.0	$16.6	3.2%
6	Readington - Roseland	Line	PSEG	($1.8)	($49.5)	$5.2	$52.9	($10.5)	$38.1	($20.7)	($69.3)	($16.3)	(3.2%)
7	BCPEP	Interface	Pepco	$11.9	($1.8)	$1.9	$15.6	$0.0	$0.0	$0.0	$0.0	$15.6	3.1%
8	Breed - Wheatland	Flowgate	MISO	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	2.7%
9	Bagley - Graceton	Line	BGE	$11.1	($0.7)	$1.8	$13.7	$0.3	($1.0)	($1.9)	($0.6)	$13.1	2.6%
10	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(2.5%)
11	Unclassified	Unclassified	Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	2.5%
12	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(2.4%)
13	Monticello - East Winamac	Flowgate	MISO	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	2.4%
14	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	2.0%
15	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	2.0%
16	Bedington - Black Oak	Interface	500	$6.2	($3.1)	$0.8	$10.0	$0.1	($0.0)	($0.3)	($0.2)	$9.8	1.9%
17	Crete - St Johns Tap	Flowgate	MISO	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1.8%
18	South Canton	Transformer	AEP	($3.4)	($11.1)	$1.1	$8.8	($0.2)	$0.5	$0.8	$0.1	$8.9	1.7%
19	Conastone - Graceton	Line	BGE	$5.4	($2.0)	$1.6	$9.0	($0.0)	($0.1)	($0.2)	($0.2)	$8.8	1.7%
20	Byron - Cherry Valley	Line	ComEd	($0.0)	($0.1)	$0.0	$0.1	($1.2)	$2.5	($5.0)	($8.7)	($8.6)	(1.7%)
21	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.7%
22	Braidwood	Transformer	ComEd	($0.2)	($7.4)	$1.2	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	1.6%
23	New Dover - Westfield	Line	PSEG	$0.5	($5.8)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
24	Michigan City - Laporte	Flowgate	MISO	($6.0)	($10.6)	$2.5	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
25	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1.3%

Figure 11-2 shows the locations of the top 10 constraints affecting PJM congestion costs in the first nine months of 2014.

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: January through September of 2014[16]



16 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

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.[17] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[18] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of September 30, 2014, PJM had 89 flowgates eligible for M2M (Market to Market) coordination and MISO had 274 flowgates eligible for M2M coordination.

Table 11-22 and Table 11-23 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2014 and the first nine months of 2013, 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 2014, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Rising flowgate made the most significant contribution to negative congestion.

Table 11-22 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September of 2014

		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	Breed - Wheatland	($16.2)	($90.3)	($9.2)	$64.9	$2.3	$1.1	$5.6	$6.8	$71.7	2,810	527
2	Benton Harbor - Palisades	($11.8)	($70.2)	($6.9)	$51.6	($0.2)	$0.7	($1.0)	($1.8)	$49.7	2,528	137
3	Monticello - East Winamac	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	3,511	1,440
4	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
5	Oak Grove - Galesburg	($22.5)	($48.6)	($2.5)	$23.5	($0.4)	$0.4	$0.1	($0.7)	$22.8	5,403	938
6	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	105
7	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
8	Michigan City - Laporte	($4.5)	($11.2)	$2.2	$8.9	$0.0	$0.0	$0.0	$0.0	$8.9	1,850	0
9	Crete - St Johns Tap	($1.4)	($6.5)	$1.3	$6.4	$0.0	$0.0	$0.0	$0.0	$6.4	606	0
10	Cumberland - Bush	($0.2)	($3.2)	$0.5	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	470	0
11	Batesville - Hubble	($1.7)	($5.6)	($0.9)	$2.9	($0.0)	($0.0)	$0.1	$0.1	$3.0	438	16
12	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
13	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
14	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
15	Rantoul - Rantoul Jct	($2.7)	($4.5)	$0.3	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	930	0
16	Bunsonville - Eugene	($4.2)	($7.4)	$0.2	$3.4	($0.1)	($0.1)	($1.2)	($1.2)	$2.1	2,060	534
17	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	165	0
18	Edwards - Kewanee	($1.6)	($3.6)	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	1,789	0
19	Pana North	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.3	($2.0)	($2.3)	($1.9)	157	8
20	Magnetation - Monticello	($0.0)	($1.0)	$0.4	$1.3	$0.3	$0.3	$0.3	$0.4	$1.7	112	20

17 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>.
18 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>.

Table 11-23 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September of 2013

		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	Breed - Wheatland	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	1,714	293
2	Monticello - East Winamac	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	1,926	542
3	Byron - Cherry Valley	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
4	Crete - St Johns Tap	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1,165	0
5	Michigan City - Laporte	($6.0)	($10.6)	$2.5	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	2,304	0
6	Benton Harbor - Palisades	($1.4)	($7.5)	$2.5	$8.6	($0.1)	$0.8	($2.1)	($2.9)	$5.7	1,700	117
7	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
8	Rantoul - Rantoul Jct	($3.7)	($5.8)	$1.6	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	1,673	0
9	Edwards - Kewanee	($2.5)	($4.1)	$2.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,095	12
10	Prairie State - W Mt. Vernon	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1,021	836
11	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($2.6)	($3.4)	($3.4)	0	83
12	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
13	Volunteer - Phipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
14	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
15	Oak Grove - Galesburg	($3.8)	($7.1)	($0.3)	$3.0	($0.3)	$0.3	($0.6)	($1.2)	$1.8	1,451	640
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.5)	($1.7)	($1.7)	0	193
17	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
18	Pleasant Prairie - Zion	($0.5)	($1.6)	$0.7	$1.8	($0.0)	($0.0)	($0.5)	($0.5)	$1.3	855	76
19	Roxana - Praxair	($2.3)	($2.6)	$0.4	$0.7	$0.3	$0.4	($1.4)	($1.4)	($0.7)	648	92
20	Bunsonville - Eugene	($1.9)	($3.6)	$0.1	$1.8	($0.0)	$0.1	($1.0)	($1.1)	$0.7	710	261

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[19] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[20]

Table 11-24 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first nine months of 2014, and which had the greatest congestion cost impact on PJM.

19 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

20 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 11-24 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September of 2014

				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	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.5	$2.0	($0.1)	($1.6)	($1.6)	0	128
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	4

Table 11-25 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September of 2013

				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	Central East	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	167
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.2)	($0.2)	0	31

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-26 and Table 11-27 show the 500 kV constraints affecting congestion costs in PJM for the first nine months of 2014 and the first nine months of 2014. 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 affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-26 Regional constraints summary (By facility): January through September of 2014

				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	$322.0	($196.8)	($10.4)	$508.4	$31.5	$73.5	$8.9	($33.1)	$475.3	4,685	967
2	West	Interface	500	($21.3)	($290.9)	($78.6)	$191.0	$16.7	$47.7	$16.8	($14.2)	$176.8	1,395	347
3	Bedington - Black Oak	Interface	500	$39.3	($41.0)	$0.2	$80.5	$3.9	$3.5	($2.3)	($1.9)	$78.6	2,386	311
4	East	Interface	500	($9.2)	($32.3)	($3.2)	$19.9	$0.3	$0.7	$0.5	$0.1	$20.0	1,710	17
5	5004/5005 Interface	Interface	500	($0.5)	($22.7)	($3.3)	$18.9	$8.1	$17.5	$7.3	($2.2)	$16.7	495	333
6	SENECA	Interface	500	$4.3	$7.7	($3.9)	($7.2)	$0.0	$0.0	$0.0	$0.0	($7.2)	1,737	0
7	AEP - DOM	Interface	500	$9.7	($10.6)	$3.9	$24.2	$5.4	$13.1	($9.6)	($17.3)	$6.9	2,186	59
8	Central	Interface	500	($5.1)	($13.7)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.5	325	10
9	Juniata	Transformer	500	$0.1	($0.2)	$0.1	$0.5	$0.1	($0.0)	($0.1)	$0.0	$0.5	253	9
10	Branchburg - Elroy	Line	500	($0.0)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	43	0

Table 11-27 Regional constraints summary (By facility): January through September of 2013

				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	$117.7	($29.5)	$12.9	$160.0	$7.5	$13.3	($9.2)	($15.1)	$144.9	4,757	915
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	1,387	79
3	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	505	150
4	Bedington - Black Oak	Interface	500	$6.2	($3.1)	$0.8	$10.0	$0.1	($0.0)	($0.3)	($0.2)	$9.8	1,172	16
5	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1,317	10
6	Conemaugh - Hunterstown	Line	500	$0.4	($2.6)	$0.3	$3.4	$0.5	$0.7	($0.7)	($0.9)	$2.5	153	68
7	Central	Interface	500	($0.9)	($3.3)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	167	0
8	East	Interface	500	($0.5)	($1.7)	($0.0)	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.1	254	4
9	Juniata	Transformer	500	$0.2	($0.3)	$0.2	$0.7	$0.4	$0.1	($0.4)	($0.1)	$0.6	227	6
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
11	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In the first nine months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first nine months of 2014, financial companies received $196.4 million in net congestion credits, an increase of $114.9 million or 141.1 percent compared to the first nine months of 2013. In the first nine months of 2014, physical companies paid $1,901.7 million in congestion charges, an increase of $1,310.7 million or 221.7 percent compared to the first nine months of 2013.

Table 11-28 Congestion cost by type of participant: January through September of 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$64.7	$65.5	($77.6)	($78.4)	($31.4)	($4.3)	($90.9)	($118.0)	$0.0	($196.4)
Physical	$440.7	($1,563.2)	$39.1	$2,043.0	$104.4	$228.7	($17.1)	($141.3)	$0.0	$1,901.7
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$0.0	$1,705.3

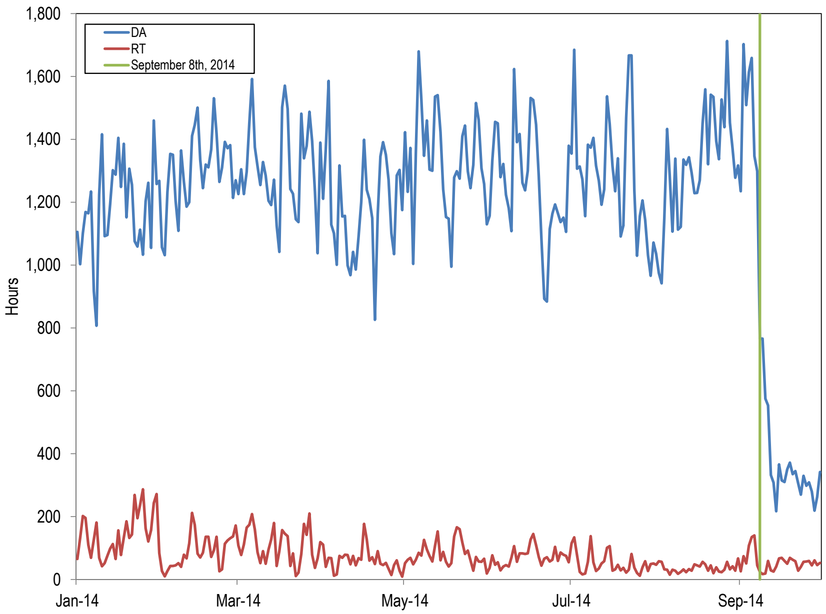
Table 11-29 Congestion cost by type of participant: January through September of 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$44.3	$35.5	$76.9	$85.7	($28.5)	$0.9	($137.7)	($167.1)	$0.0	($81.4)
Physical	$182.9	($488.1)	$44.7	$715.7	$35.4	$111.3	($48.7)	($124.6)	$0.0	$591.1
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6

Congestion-Event Summary before and after September 8th, 2014

The day-ahead congestion event hours decreased significantly corresponding with a significant reduction in UTC activity related to FERC's UTC uplift refund notice, effective September 8, 2014.[21] Figure 11-3 shows the daily day-ahead and real-time congestion event hours for the first nine months of 2014.

Figure 11-3 Daily congestion event hours: January through September 2014



21 See 18 CFR § 385.213 (2014).

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 marginal 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 net of 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 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.

The total marginal loss cost in PJM for the first nine months of 2014 was $1,243.1 million, which was comprised of load loss payments of -$47.6 million, generation loss credits of -$1,343.7 million, explicit loss costs of -$53.0 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first nine months of 2014 ranged from $68.7 million in May to $414.6 million in January. Marginal loss credits increased in the first nine months of 2014 by $136.4 million or 51.0 percent from the first nine months of 2013, from $267.6 million to $404.1 million.

Total Marginal Loss Costs

Table 11-30 shows the total marginal loss component costs for the first nine months of 2009 through 2014.

Total marginal loss costs for the first nine months of 2009 through 2014 are shown in Table 11-31 and Table 11-32. Table 11-31 shows PJM total marginal loss costs by accounting category for the first nine months of 2009 through 2014. Table 11-32 shows PJM total marginal loss costs by accounting category by market for the first nine months of 2009 through 2014.

Table 11-30 Total marginal loss component costs (Dollars (Millions)): January through September of 2009 through 2014[22]

(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%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,760	3.0%

Table 11-31 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through September of 2009 through 2014

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($62.0)	($1,028.3)	$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
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($53.0)	$0.0	$1,243.1

Table 11-32 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through September of 2009 through 2014

	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	$3.9	($2.6)	($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
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1

22 The loss costs include net inadvertent charges.

Monthly Marginal Loss Costs

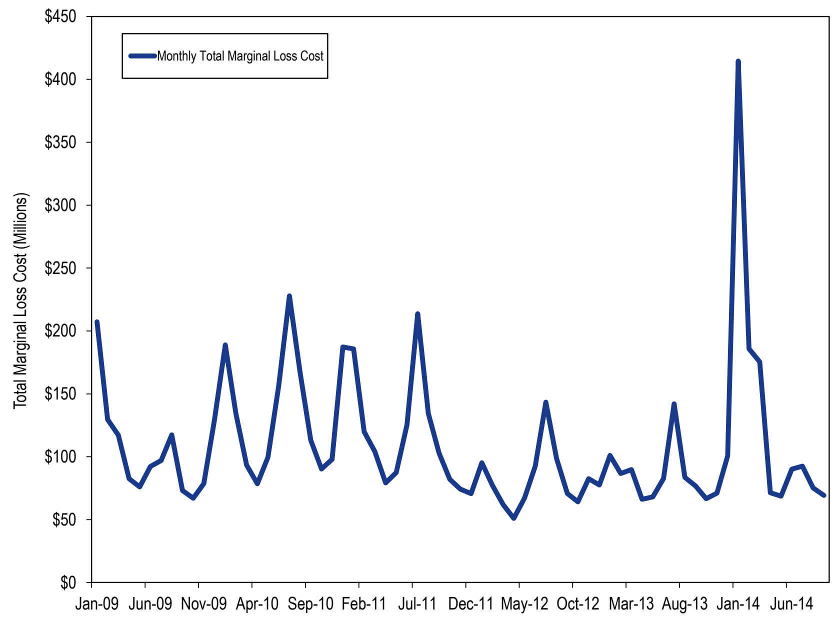
Table 11-33 shows a monthly summary of marginal loss costs by market type for the first nine months of 2013 and the first nine months of 2014.

Table 11-33 Monthly marginal loss costs by market (Dollars (Millions)): January through September of 2013 and 2014

	Marginal Loss Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$105.8	($4.7)	$0.0	$101.1	$431.1	($16.5)	$0.0	$414.6
Feb	$93.2	($6.5)	($0.0)	$86.7	$202.1	($16.3)	$0.0	$185.8
Mar	$97.2	($7.4)	($0.0)	$89.8	$198.0	($22.6)	($0.0)	$175.4
Apr	$77.7	($11.5)	($0.0)	$66.2	$83.2	($11.8)	($0.0)	$71.4
May	$80.5	($12.4)	($0.0)	$68.1	$80.3	($11.5)	$0.0	$68.7
Jun	$91.7	($9.0)	($0.0)	$82.7	$100.4	($10.2)	$0.0	$90.2
Jul	$149.2	($7.1)	($0.0)	$142.1	$102.1	($9.6)	$0.0	$92.5
Aug	$91.3	($7.8)	($0.0)	$83.6	$80.5	($5.3)	$0.0	$75.2
Sep	$85.0	($8.2)	($0.0)	$76.8	$70.3	($1.1)	$0.0	$69.2
Total	$871.6	($74.6)	($0.0)	$797.0	$1,347.9	($104.8)	$0.0	$1,243.1

Figure 11-4 shows PJM monthly marginal loss costs for January 2009 through September 2014.

Figure 11-4 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through September 2014



Marginal Loss Costs and Loss Credits

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

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 within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 11-34 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first nine months of 2009 through 2014. The total marginal loss credits increased $136.4 million in the first nine months of 2014 from the first nine months of 2013.

Table 11-34 Marginal loss credits (Dollars (Millions)): January through September of 2009 through 2014[23]

	Loss Credit Accounting (Millions)			
(Jan - Sep)	Total Energy Charges	Total Marginal Loss Charges	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	($442.6)	$757.6	($1.7)	$313.3
2013	($527.2)	$797.0	($2.1)	$267.6
2014	($833.9)	$1,243.1	($5.2)	$404.1

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. 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, plus net inadvertent energy charges. 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.

The total energy cost for the first nine months of 2014 was -$833.9 million, which was comprised of load energy payments of $50,415.3 million, generation energy credits of $51,245.6 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$3.6 million. The monthly energy costs for the first nine months of 2014 ranged from -$272.7 million in January to -$44.6 million in September.

Total Energy Costs

Table 11-35 shows total energy component costs and total PJM billing, for the first nine months of 2009 through 2014. The total energy component costs are net energy costs.

Table 11-35 Total PJM costs by energy component (Dollars (Millions)): January through September of 2009 through 2014[24]

(Jan - Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($485)	NA	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,760	(2.0%)

Energy costs for the first nine months of 2009 through 2014 are shown in Table 11-36 and Table 11-37. Table 11-36 shows PJM energy costs by accounting category for the first nine months of 2009 through 2014 and Table 11-37 shows PJM energy costs by market category for the first nine months of 2009 through 2014. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-35.

23 The net residual market 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.

24 The energy costs include net inadvertent charges.

Table 11-36 Total PJM energy costs by accounting category (Dollars (Millions)): January through September of 2009 through 2014

	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	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)

Table 11-37 Total PJM energy costs by market category (Dollars (Millions)): January through September of 2009 through 2014

	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)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)

Monthly Energy Costs

Table 11-38 shows a monthly summary of energy costs by market type for the first nine months of 2013 and the first nine months of 2014.

Table 11-38 Monthly energy costs by market type (Dollars (Millions)): January through September of 2013 and 2014

	Energy Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($69.2)	$5.8	$0.5	($63.0)	($339.8)	$68.1	($1.0)	($272.7)
Feb	($60.6)	$5.9	($0.1)	($54.8)	($163.7)	$43.5	($2.8)	($123.0)
Mar	($63.9)	$4.2	($0.3)	($60.0)	($167.3)	$50.8	($3.1)	($119.6)
Apr	($46.8)	$0.9	($0.6)	($46.5)	($90.4)	$36.7	($0.1)	($53.7)
May	($48.3)	($3.4)	($0.3)	($52.0)	($92.4)	$44.0	$0.3	($48.1)
Jun	($63.4)	$7.8	($0.6)	($56.2)	($94.7)	$33.4	$1.3	($59.9)
Jul	($110.9)	$21.4	($1.1)	($90.6)	($91.1)	$28.9	$0.7	($61.5)
Aug	($71.0)	$17.4	($0.7)	($54.3)	($79.2)	$28.2	$0.5	($50.6)
Sep	($67.2)	$18.3	($0.9)	($49.8)	($55.8)	$10.5	$0.7	($44.6)
Total	($601.3)	$78.2	($4.2)	($527.2)	($1,174.5)	$344.2	($3.6)	($833.9)

Figure 11-5 shows PJM monthly energy costs of January 2009 through September 2014.

Figure 11-5 PJM monthly energy costs (Dollars (Millions)): January 2009 through September 2014