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).[1]

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.[2] 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. Total system-wide transmission losses for 2013 were 17,389 GWh, a 2.5 percent increase compared to 2012. 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.[3] The result is that the price of energy in the constrained area 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 and marginal losses.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $147.9 million or 28.0 percent, from $529.0 million in 2012 to $676.9 million in 2013.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $231.4 million or 29.7 percent, from $779.9 million in 2012 to $1,011.3 million in 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $83.5 million or 33.3 percent from -$250.9 million in 2012 to -$334.4 million in 2013.[5]
- **Monthly Congestion.** Monthly total congestion costs in 2013 ranged from $27.8 million in April to $110.1 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI Interface, the Bridgewater - Middlesex line, and the Bedington - Black Oak Interface.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2013. Day-ahead congestion frequency increased by 44.0 percent from 249,572 congestion event hours in 2012 to 359,432 congestion event hours in 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012. 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 For more information about LMP see the *Technical Reference for PJM Markets*, "Calculating Locational Marginal Price." <http://www.monitoringanalytics.com/reports/ Technical_References/references.shtml>.

3 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.

4 The total congestion and marginal losses were calculated as of January 28, 2014, and are subject to change, based on continued PJM billing updates.

5 The balancing congestion cost is greater than the balancing congestion calculated by PJM by $0.26 million as a result of security constrained economic dispatch (SCED) software flat files format changes and the fact that SCED was down for many intervals for emergency fixes on August 8, 2013.

Real-time congestion frequency decreased by 7.6 percent from 20,921 congestion event hours in 2012 to 19,321 congestion event hours in 2013. Real-time, congestion-event hours increased on the interfaces, while congestion-event hours on the transformers, the flowgates and the transmission lines decreased.

Facilities were constrained in the Day-Ahead Energy Market more frequently than in the Real-Time Energy Market. In 2013, for only 2.0 percent of Day-Ahead Energy Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2013, for 38.1 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 2013. With $169.1 million in total congestion costs, it accounted for 25.0 percent of the total PJM congestion costs in 2013. The top five constraints in terms of congestion costs together contributed $223.7 million, or 33.0 percent, of the total PJM congestion costs in 2013. The top five constraints were the AP South Interface, the West Interface, the ATSI Interface, the Bridgewater – Middlesex line, and the Bedington - Black Oak Interface.

- **Zonal Congestion.** ComEd was the most congested zone in 2013. ComEd had -$477.3 million in total load costs, -$650.0 million in total generation credits and -$17.5 million in explicit congestion, resulting in $155.2 million in net congestion costs. The Nelson – Cordova line, the Byron - Cherry Valle flowgate, the Braidwood transformer, the Oak Grove – Galesburg flowgate and the Crete – St Johns Tap flowgate contributed $56.4 million, or 36.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2013, with $106.0 million. The AP South Interface contributed $23.5 million or 22.1 percent of the total AEP Control Zone congestion cost in 2013. The AP Control Zone was the third most congested zone in PJM in 2013, with a cost of $92.8 million.

- **Ownership.** In 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2013, financial companies received $102.8 million in net congestion credits, an increase of $19.8 million or 23.9 percent compared to 2012. In 2013, physical companies paid $779.7 million in net congestion charges, an increase of $167.7 million or 27.4 percent compared to 2012.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in 2013 increased by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million. Day-ahead net marginal loss costs in 2013 increased by $133.9 million or 13.3 percent from 2012, from $1,003.8 million to $1,137.7 million. Balancing net marginal loss costs decreased in 2013 by $80.3 million or 363.4 percent from 2012, from -$22.1 million to -$102.4 million.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in 2013 ranged from $66.2 million in April to $142.1 million in July.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) 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 energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[6] The marginal loss credits decreased in 2013 by $55.8 million or 14.4 percent from 2012, from $386.7 million to $330.9 million.

6 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), pp 63-64. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Energy Cost

- **Total Energy Costs.** Total energy costs in 2013 decreased by $108.5 million or 18.3 percent from 2012, from -$593.0 million to -$701.5 million. Day-ahead net energy costs in 2013 decreased by $224.3 million or 36.8 percent from 2012, from -$609.9 million to -$834.2 million. Balancing net energy costs in 2013 increased by $132.4 million or 1,710.3 percent from 2012, from $7.7 million to $140.1 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in 2013 ranged from -$90.8 million in July to -$44.3 million in October.

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 distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion in 2013. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Marginal losses are the costs of 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. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Increases in the LMP and fuel costs led to higher marginal loss costs in 2013 compared to 2012. Total marginal loss costs increased in 2013 by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million.

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and 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 and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8]

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/ Technical_References/references.shtml>.

8 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.

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.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for 2009 to 2013. The load-weighted average real-time LMP increased $3.43 or 9.7 percent from $35.23 in 2012 to $38.66 in 2013. The load-weighted average congestion component decreased $0.03 or 79.8 percent from $0.04 in 2012 to $0.01 in 2013. The load-weighted average loss component increased $0.01 or 38.2 percent from $0.01 in 2012 to $0.02 in 2013. The load-weighted average energy component increased $3.46 or 9.8 percent from $35.18 in 2012 to $38.64 in 2013. Given that these results are based on system average LMP including offsetting congestion components, a congestion component near zero is expected.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2013[9]

Year	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2013. The load-weighted average day-ahead LMP increased $4.37 or 12.7 percent from $34.55 in 2012 to $38.93 in 2013. The load-weighted average congestion component increased $0.03 or 26.1 percent from $0.11 in 2012 to $0.13 in 2013. The load-weighted average loss component increased $0.02 or 116.3 percent from -$0.01 in 2012 to $0.00 in 2013. The load-weighted average energy component increased $4.33 or 12.6 percent from $34.46 in 2012 to $38.79 in 2013.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2013

Year	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00

9 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.

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 11-3 for 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 11-4 for 2012 and 2013.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2012 and 2013

	2012				2013			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.55	$35.86	$0.23	$1.46	$41.11	$39.14	$0.27	$1.70
AEP	$33.15	$34.73	($0.75)	($0.83)	$35.56	$38.25	($1.78)	($0.92)
AP	$34.86	$34.91	$0.04	($0.09)	$37.70	$38.39	($0.57)	($0.11)
ATSI	$34.42	$34.99	($0.78)	$0.21	$42.12	$38.43	$3.27	$0.42
BGE	$40.03	$35.44	$2.99	$1.59	$43.52	$38.97	$2.79	$1.76
ComEd	$31.76	$35.39	($2.05)	($1.58)	$33.28	$38.65	($3.48)	($1.90)
DAY	$34.25	$35.14	($0.95)	$0.05	$36.15	$38.61	($2.35)	($0.11)
DEOK	$32.67	$35.16	($0.87)	($1.62)	$34.35	$38.57	($2.31)	($1.91)
DLCO	$33.53	$35.05	($0.47)	($1.05)	$35.70	$38.51	($1.61)	($1.20)
Dominion	$37.28	$35.45	$1.48	$0.35	$40.63	$38.84	$1.46	$0.33
DPL	$39.53	$35.53	$2.31	$1.68	$42.18	$38.96	$1.29	$1.93
EKPC	NA	NA	NA	NA	$33.96	$38.72	($2.73)	($2.02)
JCPL	$37.34	$35.92	$0.09	$1.33	$42.98	$39.54	$1.63	$1.81
Met-Ed	$36.30	$35.11	$0.67	$0.53	$39.72	$38.63	$0.34	$0.75
PECO	$36.78	$35.27	$0.61	$0.89	$39.70	$38.77	($0.11)	$1.03
PENELEC	$35.10	$34.66	($0.12)	$0.56	$38.71	$38.18	($0.10)	$0.63
Pepco	$39.08	$35.47	$2.68	$0.93	$42.78	$38.98	$2.62	$1.18
PPL	$35.44	$34.92	$0.00	$0.52	$39.26	$38.44	$0.18	$0.64
PSEG	$37.48	$35.38	$0.71	$1.39	$43.97	$38.93	$3.37	$1.67
RECO	$37.80	$36.09	$0.42	$1.29	$45.81	$39.65	$4.53	$1.63
PJM	$35.23	$35.18	$0.04	$0.01	$38.66	$38.64	$0.01	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2012 and 2013

	2012				2013			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.36	$35.08	$0.66	$1.62	$41.48	$39.23	$0.61	$1.64
AEP	$32.71	$34.19	($0.51)	($0.97)	$36.44	$38.58	($1.26)	($0.88)
AP	$34.29	$34.26	$0.09	($0.06)	$38.23	$38.62	($0.21)	($0.18)
ATSI	$33.55	$34.32	($0.69)	($0.08)	$38.13	$38.69	($0.85)	$0.29
BGE	$39.55	$34.85	$2.76	$1.93	$44.32	$39.17	$3.46	$1.69
ComEd	$30.72	$34.60	($1.98)	($1.90)	$34.12	$38.86	($3.04)	($1.70)
DAY	$33.76	$34.58	($0.65)	($0.16)	$37.13	$38.89	($1.58)	($0.18)
DEOK	$32.18	$34.45	($0.49)	($1.79)	$35.46	$38.70	($1.54)	($1.69)
DLCO	$33.05	$34.42	($0.30)	($1.07)	$36.35	$38.75	($1.17)	($1.22)
Dominion	$36.56	$34.76	$1.31	$0.48	$41.34	$39.15	$2.03	$0.16
DPL	$38.91	$34.94	$1.86	$2.11	$42.55	$39.10	$1.56	$1.89
EKPC	NA	NA	NA	NA	$35.65	$39.37	($1.68)	($2.04)
JCPL	$37.03	$35.10	$0.47	$1.47	$42.86	$39.48	$1.66	$1.73
Met-Ed	$35.44	$34.29	$0.50	$0.65	$40.04	$38.62	$0.83	$0.59
PECO	$36.40	$34.62	$0.72	$1.06	$40.14	$38.87	$0.32	$0.94
PENELEC	$34.69	$33.95	$0.12	$0.62	$39.29	$38.14	$0.38	$0.77
Pepco	$38.26	$34.58	$2.39	$1.29	$43.16	$38.70	$3.33	$1.14
PPL	$34.82	$34.22	$0.12	$0.48	$39.67	$38.55	$0.65	$0.46
PSEG	$37.25	$34.81	$0.79	$1.65	$44.65	$39.17	$3.78	$1.70
RECO	$36.91	$35.20	$0.34	$1.36	$45.55	$39.37	$4.55	$1.62
PJM	$34.55	$34.46	$0.11	($0.01)	$38.93	$38.79	$0.13	$0.00

Component Costs

Table 11-5 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 11-5 Total PJM costs by component (Dollars (Millions)): 2009 through 2013[10, 11]

	Component Costs (Millions)					
Year	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,423	$2,260	$34,771	6.5%
2011	($794)	$1,380	$999	$1,585	$35,887	4.4%
2012	($593)	$982	$529	$918	$29,181	3.1%
2013	($702)	$1,035	$677	$1,011	$33,862	3.0%

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[12] 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.[13]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product

10 The energy costs, loss costs and congestion costs include net inadvertent charges.

11 Total PJM billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

12 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.

13 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.

of the deviations between the real-time and day-ahead transacted MWs and the differences between the real-time CLMP at the transactions' sources and sinks.

- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

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.[15]

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. The net congestion bill is the source of payments to FTR holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

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.[16] 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 control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment).

14 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

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

16 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.

Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

Total congestion costs in PJM in 2013 were $676.9 million, which was comprised of load congestion payments of $287.1 million, generation credits of -$461.3 million and explicit congestion of -$71.5 million (Table 11-6.)

Total Congestion

Table 11-6 shows total congestion by year from 2008 through 2013.

Table 11-6 Total PJM congestion (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$34,306	6.0%
2009	$719.0	(65.0%)	$26,550	2.7%
2010	$1,423.3	98.0%	$34,771	4.1%
2011	$999.0	(29.8%)	$35,887	2.8%
2012	$529.0	(47.0%)	$29,181	1.8%
2013	$676.9	28.0%	$33,862	2.0%

Total congestion costs in Table 11-7 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[17, 18]

Table 11-7 shows the congestion costs by category for 2013. The 2013 PJM total congestion costs were comprised of $287.1 million in load congestion payments, -$461.3 million in generation congestion credits, and -$71.5 million in explicit congestion costs.

Table 11-7 Total PJM congestion costs by accounting category (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$1,034.4	($1,053.9)	($36.5)	$0.0	$2,051.8
2009	$253.3	($515.1)	($49.4)	$0.0	$719.0
2010	$338.9	($1,167.0)	($82.6)	($0.0)	$1,423.3
2011	$454.0	($668.1)	($123.1)	$0.0	$999.0
2012	$115.1	($467.4)	($53.5)	$0.0	$529.0
2013	$287.1	($461.3)	($71.5)	$0.0	$676.9

Table 11-8 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9

17 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).

18 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).

Monthly Congestion

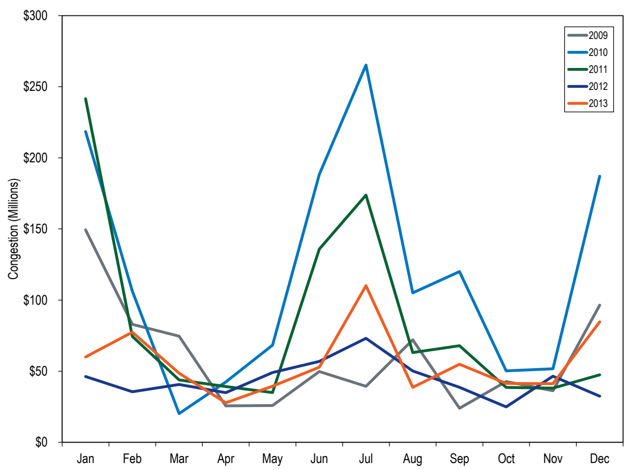
Table 11-9 shows that monthly total congestion costs ranged from $27.8 million to $110.1 million in 2013. Table 11-9 shows that monthly congestion costs in 2013 were higher than in 2012.

Table 11-9 Monthly PJM congestion costs by market (Dollars (Millions)): 2012 to 2013

	Congestion Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.1)	$0.0	$40.7	$69.9	($21.4)	($0.0)	$48.5
Apr	$72.0	($37.1)	$0.0	$34.9	$37.7	($9.9)	$0.0	$27.8
May	$67.2	($18.2)	($0.0)	$49.1	$75.3	($35.8)	($0.0)	$39.5
Jun	$69.6	($12.7)	($0.0)	$56.8	$82.2	($29.4)	($0.0)	$52.8
Jul	$91.0	($17.9)	$0.0	$73.1	$131.3	($21.3)	$0.0	$110.1
Aug	$60.8	($10.6)	$0.0	$50.2	$46.0	($7.3)	$0.0	$38.6
Sep	$61.8	($23.1)	($0.0)	$38.7	$97.0	($42.1)	$0.0	$54.9
Oct	$54.4	($29.6)	$0.0	$24.9	$54.6	($13.3)	($0.0)	$41.4
Nov	$66.4	($19.9)	$0.0	$46.5	$59.3	($18.1)	($0.0)	$41.2
Dec	$55.8	($23.4)	$0.0	$32.4	$95.9	($11.2)	$0.0	$84.7
Total	$779.9	($250.9)	$0.0	$529.0	$1,011.3	($334.4)	$0.0	$676.9

Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2013.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 to 2013



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 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 also consistent with the way in which PJM reports real-time congestion. In 2013, there were 359,432 day-ahead, congestion-event hours compared to 249,572 day-ahead, congestion-event hours in 2012. In 2013, there were 19,321 real-time, congestion-event hours compared to 20,921 real-time, congestion-event hours in 2012.

During 2013, for only 2.0 percent of day-ahead energy market facility constrained hours were the same facilities also constrained in the Real-Time Energy Market. During 2013, for 38.1 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 2013. With $169.1 million in total congestion costs, it accounted for 33.2 percent of the total PJM congestion costs in 2013. The top five constraints in terms of congestion costs together contributed $223.7 million, or 44.0 percent, of the total PJM congestion costs in 2013. The top five constraints were the AP South Interface, the West Interface, the ATSI Interface, and the Bridgewater – Middlesex line, and the Bedington - Black Oak flowgate.

Congestion by Facility Type and Voltage

In 2013, compared to 2012, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours decreased on all types of facilities except internal PJM interfaces.

Day-ahead congestion costs decreased on the flowgates in 2013 compared to 2012 and increased on PJM interfaces, transmission lines and transformers in 2013 compared to the 2012. Balancing congestion costs increased on flowgates, transmission lines and interfaces and decreased on transformers in 2013 compared to 2012.

Table 11-10 provides congestion-event hour subtotals and congestion cost subtotals comparing 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19, 20] For comparison, this information is presented in Table 11-11 for 2012.[21]

Table 11-12 and Table 11-13 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 11-12. In 2013, there were 359,432 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 7,240 (2.0 percent) were also constrained in the Real-Time Energy Market. In 2012, among the 249,572 day-ahead congestion event hours, only 8,118 (3.3 percent) were binding in the Real-Time Energy Market.[22]

Table 11-10 Congestion summary (By facility type): 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	($52.2)	($187.5)	$20.0	$155.3	$0.9	$12.3	($40.1)	($51.4)	$103.9	34,549	5,707
Interface	$180.7	($95.3)	$15.7	$291.6	$23.6	$36.6	($36.1)	($49.1)	$242.5	15,625	1,745
Line	$87.9	($262.2)	$62.2	$412.3	($21.4)	$68.9	($107.0)	($197.2)	$215.1	198,392	10,025
Other	$9.8	($0.8)	$6.6	$17.1	($0.3)	$0.2	($3.8)	($4.3)	$12.8	10,821	161
Transformer	$29.0	($63.5)	$25.5	$118.0	$2.4	$11.1	($23.2)	($31.8)	$86.2	100,045	1,683
Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	NA	NA
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	359,432	19,321

Table 11-11 Congestion summary (By facility type): 2012

	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	($60.2)	($189.7)	$39.2	$168.7	($5.8)	$10.1	($81.4)	($97.3)	$71.4	28,330	7,755
Interface	$70.8	($68.8)	$2.9	$142.5	$14.6	$21.6	($3.6)	($10.6)	$131.9	7,005	737
Line	$78.1	($193.9)	$63.3	$335.3	($9.1)	$31.8	($82.9)	($123.8)	$211.5	146,041	10,174
Other	$9.6	($4.3)	$2.1	$15.9	($0.6)	$0.0	($0.9)	($1.6)	$14.4	7,977	431
Transformer	$31.2	($54.6)	$22.6	$108.3	$4.4	$3.8	($15.5)	($14.9)	$93.5	60,219	1,824
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,921

19 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.

20 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

21 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.

22 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.

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 11-13. In 2013, there were 19,321 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 7,360 (38.1 percent) were also constrained in the Day-Ahead Energy Market. In 2012, among the 20,921 real-time congestion event hours, only 8,031 (38.4 percent) were also in the Day-Ahead Energy Market.

Table 11-12 Congestion event hours (Day-Ahead against Real-Time): 2012 to 2013

	Congestion Event Hours					
	2012			2013		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	28,330	3,239	11.4%	34,549	2,177	6.3%
Interface	7,005	369	5.3%	15,625	1,228	7.9%
Line	146,041	3,516	2.4%	198,392	3,093	1.6%
Other	7,977	265	3.3%	10,821	168	1.6%
Transformer	60,219	729	1.2%	100,045	574	0.6%
Total	249,572	8,118	3.3%	359,432	7,240	2.0%

Table 11-13 Congestion event hours (Real-Time against Day-Ahead): 2012 to 2013

	Congestion Event Hours					
	2012			2013		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	7,755	3,320	42.8%	5,707	2,314	40.5%
Interface	737	395	53.6%	1,745	1,329	76.2%
Line	10,174	3,402	33.4%	10,025	3,044	30.4%
Other	431	229	53.1%	161	106	65.8%
Transformer	1,824	685	37.6%	1,683	567	33.7%
Total	20,921	8,031	38.4%	19,321	7,360	38.1%

Table 11-14 shows congestion costs by facility voltage class for 2013. In comparison to 2012 (shown in Table 11-15), congestion costs decreased for facilities rated at 138 kV, and 115 kV 2013.

Table 11-14 Congestion summary (By facility voltage): 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	$4.6	($17.0)	$8.5	$30.1	($0.2)	$0.5	$0.7	$0.1	$30.2	10,457	22
500	$177.8	($106.3)	$19.1	$303.1	$29.0	$39.7	($49.3)	($60.0)	$243.1	20,509	2,144
345	($41.7)	($163.7)	$18.5	$140.5	$0.0	$14.8	($49.9)	($64.7)	$75.7	59,043	3,933
230	$83.6	($147.6)	$39.7	$270.8	($2.9)	$52.1	($53.4)	($108.4)	$162.4	58,887	3,629
161	($9.9)	($20.5)	($0.8)	$9.8	($1.3)	$0.7	($3.7)	($5.6)	$4.2	3,552	1,075
138	($15.2)	($160.4)	$40.1	$185.3	($7.3)	$16.6	($48.8)	($72.7)	$112.6	158,834	6,398
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$24.3	$0.9	$3.9	$27.3	($5.2)	($0.3)	($5.3)	($10.2)	$17.1	21,349	1,348
69	$26.2	$3.0	$0.1	$23.3	($7.0)	$4.8	($0.4)	($12.2)	$11.0	18,842	743
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	7,401	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	9,999	9,999
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	369,431	29,320

Table 11-15 Congestion summary (By facility voltage): 2012

	Congestion Costs (Millions)									Event Hours	
	Day Ahead				Balancing						
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.2)	($3.4)	$3.2	$6.5	$0.2	($0.1)	($0.1)	$0.1	$6.6	3,412	89
500	$75.3	($79.3)	$5.2	$159.9	$19.7	$25.8	($8.4)	($14.6)	$145.3	12,025	1,129
345	($41.6)	($135.0)	$23.7	$117.1	$1.6	$7.8	($35.7)	($41.9)	$75.2	34,038	3,628
230	$67.2	($72.4)	$19.8	$159.3	$4.8	$11.0	($38.7)	($44.9)	$114.5	35,443	4,052
161	($14.3)	($23.3)	$3.8	$12.7	($1.5)	$1.9	($10.2)	($13.6)	($0.9)	3,622	1,407
138	($9.1)	($202.2)	$69.7	$262.9	($9.0)	$15.5	($89.6)	($114.1)	$148.8	130,402	8,660
115	$24.1	($1.5)	$3.6	$29.2	($0.5)	$2.1	($1.4)	($4.0)	$25.2	18,614	901
69	$28.0	$5.9	$1.1	$23.1	($11.8)	$3.3	($0.1)	($15.3)	$7.9	10,531	1,053
34	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	1,470	2
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,921

Constraint Duration

Table 11-16 lists the constraints in 2012 and 2013 that were most frequently in effect and Table 11-17 shows the constraints which experienced the largest change in congestion-event hours from 2012 to 2013.

Table 11-16 Top 25 constraints with frequent occurrence: 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	18,619	8,676	(9,943)	0	0	0	213%	99%	(114%)	0%	0%	0%
2	Braidwood	Transformer	0	8,252	8,252	0	0	0	0%	94%	94%	0%	0%	0%
3	AP South	Interface	2,586	6,330	3,744	351	1,138	787	30%	72%	43%	4%	13%	9%
4	Gould Street - Westport	Line	1,470	7,401	5,931	2	21	19	17%	84%	67%	0%	0%	0%
5	Sunbury	Transformer	0	6,866	6,866	0	0	0	0%	78%	78%	0%	0%	0%
6	Tanners Creek	Transformer	1,911	6,846	4,935	0	0	0	22%	78%	56%	0%	0%	0%
7	Nelson - Cordova	Line	2,643	5,764	3,121	288	244	(44)	30%	66%	35%	3%	3%	(1%)
8	Howard - Shelby	Line	2,460	5,489	3,029	0	0	0	28%	62%	34%	0%	0%	0%
9	Clinch River	Transformer	0	5,168	5,168	0	0	0	0%	59%	59%	0%	0%	0%
10	Readington - Roseland	Line	1,083	4,177	3,094	95	817	722	12%	48%	35%	1%	9%	8%
11	West Moulton-City Of St. Marys	Line	1,099	4,176	3,077	0	0	0	13%	48%	35%	0%	0%	0%
12	Oak Grove - Galesburg	Flowgate	3,622	3,177	(445)	1,359	888	(471)	41%	36%	(5%)	16%	10%	(5%)
13	Mardela - Vienna	Line	206	3,747	3,541	126	213	87	2%	43%	40%	1%	2%	1%
14	Rockport Works	Transformer	595	3,921	3,326	0	0	0	7%	45%	38%	0%	0%	0%
15	Haurd - Steward	Line	1,708	3,588	1,880	1	0	(1)	19%	41%	21%	0%	0%	(0%)
16	Hunlock Creek - A.G.A. Gas	Line	256	3,578	3,322	0	0	0	3%	41%	38%	0%	0%	0%
17	Michigan City - Laporte	Flowgate	873	3,382	2,509	40	0	(40)	10%	39%	29%	0%	0%	(0%)
18	Rocky Mount - Battleboro	Line	105	2,945	2,840	0	430	430	1%	34%	32%	0%	5%	5%
19	Bridgewater - Middlesex	Line	847	3,046	2,199	31	257	226	10%	35%	25%	0%	3%	3%
20	South Cadiz	Transformer	1,578	3,283	1,705	0	0	0	18%	37%	19%	0%	0%	0%
21	Eldred - Sunbury	Line	0	3,035	3,035	0	0	0	0%	35%	35%	0%	0%	0%
22	Zion	Line	325	3,018	2,693	0	0	0	4%	34%	31%	0%	0%	0%
23	Huntingdon - Huntingdon1	Line	3,421	3,011	(410)	0	0	0	39%	34%	(5%)	0%	0%	0%
24	Breed - Wheatland	Flowgate	2,821	2,344	(477)	428	658	230	32%	27%	(6%)	5%	7%	3%
25	Danville - East Danville	Line	2,234	2,982	748	14	13	(1)	26%	34%	8%	0%	0%	(0%)

Table 11-17 Top 25 constraints with largest year-to-year change in occurrence: 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	18,619	8,676	(9,943)	0	0	0	213%	99%	(114%)	0%	0%	0%
2	Braidwood	Transformer	0	8,252	8,252	0	0	0	0%	94%	94%	0%	0%	0%
3	Sunbury	Transformer	0	6,866	6,866	0	0	0	0%	78%	78%	0%	0%	0%
4	Gould Street - Westport	Line	1,470	7,401	5,931	2	21	19	17%	84%	67%	0%	0%	0%
5	Clinch River	Transformer	0	5,168	5,168	0	0	0	0%	59%	59%	0%	0%	0%
6	Tanners Creek	Transformer	1,911	6,846	4,935	0	0	0	22%	78%	56%	0%	0%	0%
7	AP South	Interface	2,586	6,330	3,744	351	1,138	787	30%	72%	43%	4%	13%	9%
8	Readington - Roseland	Line	1,083	4,177	3,094	95	817	722	12%	48%	35%	1%	9%	8%
9	Mardela - Vienna	Line	206	3,747	3,541	126	213	87	2%	43%	40%	1%	2%	1%
10	Graceton - Raphael Road	Line	2,664	0	(2,664)	723	0	(723)	30%	0%	(30%)	8%	0%	(8%)
11	Rockport Works	Transformer	595	3,921	3,326	0	0	0	7%	45%	38%	0%	0%	0%
12	Hunlock Creek - A.G.A. Gas	Line	256	3,578	3,322	0	0	0	3%	41%	38%	0%	0%	0%
13	Rocky Mount - Battleboro	Line	105	2,945	2,840	0	430	430	1%	34%	32%	0%	5%	5%
14	Nelson - Cordova	Line	2,643	5,764	3,121	288	244	(44)	30%	66%	35%	3%	3%	(1%)
15	West Moulton-City Of St. Marys	Line	1,099	4,176	3,077	0	0	0	13%	48%	35%	0%	0%	0%
16	Eldred - Sunbury	Line	0	3,035	3,035	0	0	0	0%	35%	35%	0%	0%	0%
17	Howard - Shelby	Line	2,460	5,489	3,029	0	0	0	28%	62%	34%	0%	0%	0%
18	Bayway - Federal Square	Line	3,034	155	(2,879)	48	0	(48)	35%	2%	(33%)	1%	0%	(1%)
19	Zion	Line	325	3,018	2,693	0	0	0	4%	34%	31%	0%	0%	0%
20	Electric Junction - Frontenac	Line	0	2,540	2,540	0	0	0	0%	29%	29%	0%	0%	0%
21	Bagley - Graceton	Line	0	2,087	2,087	0	440	440	0%	24%	24%	0%	5%	5%
22	Bellefonte - Grangston	Line	2,603	127	(2,476)	0	0	0	30%	1%	(28%)	0%	0%	0%
23	Michigan City - Laporte	Flowgate	873	3,382	2,509	40	0	(40)	10%	39%	29%	0%	0%	(0%)
24	Bridgewater - Middlesex	Line	847	3,046	2,199	31	257	226	10%	35%	25%	0%	3%	3%
25	Big Sandy - Grangston	Line	3,066	651	(2,415)	0	0	0	35%	7%	(28%)	0%	0%	0%

Constraint Costs

Table 11-18 and Table 11-19 present the top constraints affecting congestion costs by facility for the periods 2013 and 2012.

Table 11-18 Top 25 constraints affecting PJM congestion costs (By facility): 2013

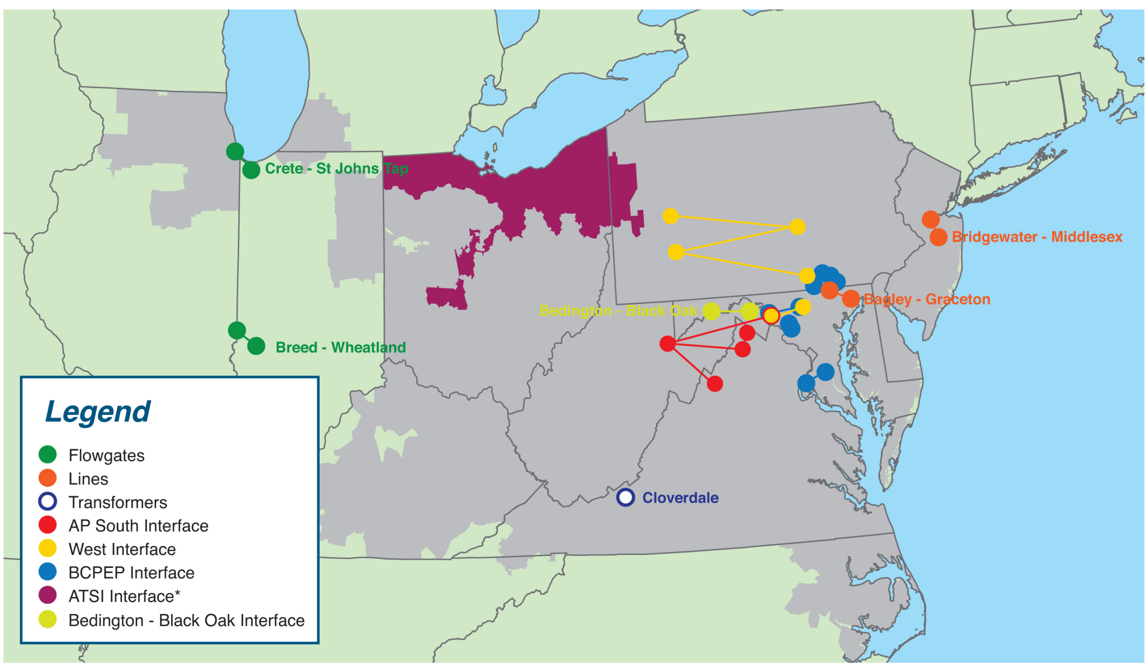
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013
1	AP South	Interface	500	$139.8	($32.8)	$13.2	$185.8	$8.2	$15.5	($9.3)	($16.7)	$169.1	25.0%
2	West	Interface	500	$4.7	($27.9)	($0.6)	$32.0	$3.0	$3.3	($1.1)	($1.4)	$30.7	4.5%
3	Bridgewater - Middlesex	Line	PSEG	$0.4	($26.9)	$2.7	$30.0	$2.2	$4.9	($2.2)	($5.0)	$25.0	3.7%
4	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(3.5%)
5	Bedington - Black Oak	Interface	500	$16.4	($8.1)	$0.6	$25.0	$0.1	$2.2	($0.4)	($2.6)	$22.4	3.3%
6	Breed - Wheatland	Flowgate	MISO	($5.5)	($27.6)	$0.9	$22.9	$0.3	($0.4)	($3.9)	($3.1)	$19.8	2.9%
7	BCPEP	Interface	Pepco	$15.8	($3.2)	$1.8	$20.9	$0.2	$1.9	$0.6	($1.2)	$19.7	2.9%
8	Bagley - Graceton	Line	BGE	$15.8	($2.1)	$2.3	$20.1	$0.4	($0.9)	($2.1)	($0.8)	$19.3	2.9%
9	Cloverdale	Transformer	AEP	$8.3	($3.9)	$4.9	$17.1	$0.0	$0.0	$0.0	$0.0	$17.1	2.5%
10	Unclassified	Unclassified	Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	2.4%
11	Crete - St Johns Tap	Flowgate	MISO	($3.2)	($13.7)	$4.6	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	2.2%
12	Monticello - East Winamac	Flowgate	MISO	($2.5)	($27.8)	$4.2	$29.5	$0.3	$5.4	($11.4)	($16.6)	$12.9	1.9%
13	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(1.9%)
14	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.1)	$5.2	($6.9)	($12.2)	($12.2)	(1.8%)
15	Braidwood	Transformer	ComEd	($0.2)	($9.9)	$1.7	$11.4	$0.0	$0.0	$0.0	$0.0	$11.4	1.7%
16	5004/5005 Interface	Interface	500	$0.9	($12.4)	($0.5)	$12.8	$1.6	$4.5	$0.5	($2.3)	$10.5	1.6%
17	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	1.5%
18	Benton Harbor - Palisades	Flowgate	MISO	($1.8)	($12.1)	$2.2	$12.5	($0.1)	$0.8	($2.0)	($2.8)	$9.7	1.4%
19	Conastone - Graceton	Line	BGE	$5.6	($2.1)	$1.7	$9.4	($0.0)	($0.1)	($0.2)	($0.2)	$9.2	1.4%
20	South Canton	Transformer	AEP	($3.5)	($11.4)	$1.2	$9.1	($0.2)	$0.5	$0.8	$0.1	$9.1	1.3%
21	AEP - DOM	Interface	500	$4.9	($4.1)	$1.8	$10.8	$0.1	$0.4	($1.5)	($1.8)	$9.0	1.3%
22	Wescosville	Transformer	PPL	$3.2	($7.3)	$1.3	$11.7	$1.1	$1.7	($2.1)	($2.8)	$9.0	1.3%
23	Nelson - Cordova	Line	ComEd	($19.7)	($38.2)	$1.4	$19.9	($1.1)	$0.6	($9.4)	($11.1)	$8.8	1.3%
24	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.3%
25	Byron - Cherry Valley	Line	ComEd	$0.0	($0.2)	$0.1	$0.3	($1.2)	$2.5	($5.0)	($8.7)	($8.4)	(1.2%)

Table 11-19 Top 25 constraints affecting PJM congestion costs (By facility): 2012

				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
1	AP South	Interface	500	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	12.9%
2	Graceton - Raphael Road	Line	BGE	$26.5	($7.7)	($1.1)	$33.1	$1.0	($1.2)	($0.3)	$1.9	$35.0	6.6%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	5.7%
4	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	4.6%
5	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	3.6%
6	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.8	($8.5)	($8.3)	$15.2	2.9%
7	Belvidere - Woodstock	Line	ComEd	($0.9)	($8.5)	$0.2	$7.7	($2.4)	$3.3	($16.3)	($22.0)	($14.3)	(2.7%)
8	Monticello - East Winamac	Flowgate	MISO	($0.2)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	2.6%
9	Nelson - Cordova	Line	ComEd	($19.3)	($34.3)	$6.9	$21.9	($0.9)	$1.7	($7.9)	($10.5)	$11.3	2.1%
10	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.3	$0.6	$0.9	$0.2	($0.1)	$10.2	1.9%
11	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	1.8%
12	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	1.7%
13	Rantoul - Rantoul Jct	Flowgate	MISO	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	1.5%
14	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.9	$0.1	$0.0	($0.0)	$0.0	$7.9	1.5%
15	Crete - St Johns Tap	Flowgate	MISO	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	1.4%
16	Pleasant Valley - Belvidere	Line	ComEd	($2.3)	($8.5)	$1.6	$7.8	$0.1	$0.1	($0.8)	($0.7)	$7.1	1.3%
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	1.3%
18	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.2)	$7.0	($0.2)	$0.1	$0.2	($0.0)	$7.0	1.3%
19	Sporn	Transformer	AEP	($0.1)	($0.6)	$6.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	1.2%
20	Harwood - Susquehanna	Line	PPL	$0.7	($5.4)	$0.3	$6.4	$0.1	$0.1	$0.1	$0.1	$6.5	1.2%
21	Unclassified	Unclassified	Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	1.2%
22	Leonia - New Milford	Line	PSEG	$1.5	$1.8	$2.7	$2.4	($0.4)	$0.4	($7.2)	($7.9)	($5.6)	(1.0%)
23	Breed - Wheatland	Flowgate	MISO	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	1.0%
24	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1.0%
25	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.0%

Figure 11-2 shows the locations of the top 10 constraints affecting PJM congestion costs in 2013.

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: 2013[23]



* ATSI is comprised of all tie lines into the ATSI transmission zone.

23 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.[24] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[25] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2013, PJM had 159 flowgates eligible for M2M (Market to Market) coordination and MISO had 265 flowgates eligible for M2M coordination.

Table 11-20 and Table 11-21 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2013 and 2012, 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 2013, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 11-20 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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	($5.5)	($27.6)	$0.9	$22.9	$0.3	($0.4)	($3.9)	($3.1)	$19.8	2,344	658
2	Crete - St Johns Tap	($3.2)	($13.7)	$4.6	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	1,943	0
3	Monticello - East Winamac	($2.5)	($27.8)	$4.2	$29.5	$0.3	$5.4	($11.4)	($16.6)	$12.9	2,041	554
4	Byron - Cherry Valley	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
5	Benton Harbor - Palisades	($1.8)	($12.1)	$2.2	$12.5	($0.1)	$0.8	($2.0)	($2.8)	$9.7	2,495	114
6	Michigan City - Laporte	($7.8)	($13.8)	$2.2	$8.2	$0.0	$0.0	$0.0	$0.0	$8.2	3,382	0
7	Oak Grove - Galesburg	($8.5)	($16.7)	($0.4)	$7.9	($0.5)	$0.6	($0.5)	($1.6)	$6.3	3,177	888
8	Cumberland - Bush	($1.2)	($8.6)	$1.2	$8.6	$0.7	$1.7	($3.3)	($4.3)	$4.3	2,465	213
9	Edwards - Kewanee	($3.3)	($5.5)	$2.1	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	2,672	12
10	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.1	($3.2)	($4.1)	($4.1)	0	106
11	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
12	Rantoul - Rantoul Jct	($4.0)	($6.3)	$1.4	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	1,722	0
13	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
14	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
15	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.9)	($2.1)	($2.1)	0	222
17	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
18	Hegew	($0.3)	($1.9)	$0.3	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	225	0
19	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
20	Pleasant Prairie - Zion	($0.5)	($1.7)	$0.8	$1.9	($0.0)	($0.0)	($0.5)	($0.5)	$1.4	1,010	76

24 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>.

25 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 11-21 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2012

		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	0
2	Monticello - East Winamac	($0.2)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	2,734	578
3	Rantoul - Rantoul Jct	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	2,036	315
4	Crete - St Johns Tap	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	2,377	277
5	Prairie State - W Mt. Vernon	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	1,483	1,015
6	Breed - Wheatland	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	2,821	428
7	Rising	($3.1)	($3.2)	$2.3	$2.4	($1.2)	$0.8	($5.4)	($7.4)	($5.0)	408	363
8	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	$0.1	$0.4	($4.0)	($4.3)	($4.3)	0	331
9	Benton Harbor - Palisades	($0.6)	($5.5)	($0.8)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.8	840	71
10	Miami Fort - Hebron	($1.8)	($5.7)	($0.2)	$3.7	($0.1)	($0.0)	$0.1	$0.0	$3.7	1,053	76
11	Palisades - Roosevelt	($0.9)	($5.6)	($0.6)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.7	855	209
12	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($11.1)	($11.8)	($1.3)	2,053	316
13	Brokaw	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($1.1)	($1.2)	($1.2)	0	81
14	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($0.2)	($1.1)	($1.1)	0	36
15	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.2	$0.0	($0.1)	($0.3)	($0.2)	$1.0	314	68
16	Michigan City - Maple	($1.0)	($0.7)	$0.5	$0.2	($0.4)	($0.1)	($0.8)	($1.1)	($0.9)	73	51
17	Beaver Channel - Albany	($6.0)	($17.0)	($0.1)	$11.0	($4.8)	($0.4)	($5.7)	($10.2)	$0.8	1,256	460
18	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.8)	($0.8)	0	20
19	Dune Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	61
20	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	74

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.[26]

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.[27]

Table 11-22 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2013, and which had the greatest congestion cost impact on PJM.

Table 11-22 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 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

26 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).

27 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).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-23 and Table 11-24 show the 500 kV constraints impacting congestion costs in PJM for 2013 and 2012. 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.

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.

Table 11-23 Regional constraints summary (By facility): 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	$139.8	($32.8)	$13.2	$185.8	$8.2	$15.5	($9.3)	($16.7)	$169.1	6,330	1,138
2	West	Interface	500	$4.7	($27.9)	($0.6)	$32.0	$3.0	$3.3	($1.1)	($1.4)	$30.7	1,845	95
3	Bedington - Black Oak	Interface	500	$16.4	($8.1)	$0.6	$25.0	$0.1	$2.2	($0.4)	($2.6)	$22.4	2,148	164
4	5004/5005 Interface	Interface	500	$0.9	($12.4)	($0.5)	$12.8	$1.6	$4.5	$0.5	($2.3)	$10.5	562	196
5	AEP - DOM	Interface	500	$4.9	($4.1)	$1.8	$10.8	$0.1	$0.4	($1.5)	($1.8)	$9.0	2,746	38
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	East	Interface	500	($0.9)	($3.3)	($0.1)	$2.2	$0.0	$0.0	$0.0	($0.0)	$2.2	504	13
8	Central	Interface	500	($0.9)	($3.5)	($0.5)	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	195	0
9	Juniata	Transformer	500	$0.2	($0.6)	$0.3	$1.1	$0.4	$0.1	($0.4)	($0.1)	$1.0	376	7
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

Table 11-24 Regional constraints summary (By facility): 2012

				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	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	2,586	351
2	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	841	130
3	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	780	54
4	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	2,095	61
5	East	Interface	500	($2.6)	($8.1)	($0.6)	$4.8	$0.1	$0.5	($0.1)	($0.5)	$4.4	209	5
6	5004/5005 Interface	Interface	500	$0.2	($4.1)	$0.5	$4.8	$2.5	$3.5	$0.3	($0.6)	$4.2	191	128
7	Conemaugh - Hunterstown	Line	500	$0.4	($1.3)	$0.1	$1.7	$0.1	$2.0	($1.9)	($3.9)	($2.1)	38	117
8	Juniata	Transformer	500	$0.4	($0.6)	$0.3	$1.3	$0.2	$0.0	($0.2)	($0.1)	$1.2	299	38
9	Central	Interface	500	($0.9)	($1.6)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	214	2
10	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
11	Nagel	Line	500	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	128	0
12	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	12	19

Table 11-25 Congestion cost by type of participant: 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	$50.2	$45.7	$84.6	$89.1	($34.1)	$1.5	($156.4)	($192.0)	$0.0	($102.8)
Physical	$230.9	($638.2)	$53.0	$922.1	$40.0	$129.8	($52.6)	($142.4)	$0.0	$779.7
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9

Table 11-26 Congestion cost by type of participant: 2012

	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	($1.6)	$8.6	$92.0	$81.8	($24.9)	($1.2)	($141.1)	($164.8)	$0.0	($83.0)
Physical	$137.1	($521.0)	$39.9	$698.1	$27.9	$69.7	($44.3)	($86.0)	$0.0	$612.0
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$0.0	$529.0

In 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2013, financial companies received $102.8 million, an increase of $19.8 million or 23.9 percent compared to 2012. In 2013, physical companies paid $779.7 million in congestion charges, an increase of $167.7 million or 27.4 percent compared to 2012.

Marginal Losses

On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[28] The primary benefit of a marginal loss calculation is that it more accurately reflects the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. There is a separate marginal loss price for every location on the power grid. This marginal loss component of LMP (MLMP) is a component of LMP.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[29] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to load on a load ratio share basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load

28 OATT. Attachment K-Appendix (Market Operations) §3.4.
29 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Payment to load is appropriate as load is the source of the surplus.

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.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[30]

The total marginal loss cost in PJM for 2013 was $1,035.3 million, which was comprised of load loss

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

payments of -$4.1 million, generation loss credits of -$1,083.3 million, explicit loss costs of -$43.9 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in 2013 ranged from $66.2 million in April to $142.1 million in July. Marginal loss credits decreased in 2013 by $55.8 million or 14.4 percent from 2012, from $386.7 million to $330.9 million.

Total Marginal Loss Costs

Table 11-27 shows the total marginal loss component costs for 2009 through 2013. Given that these results are based on system average marginal losses including offsetting marginal loss components, low total marginal loss component costs are expected.

Table 11-27 Total PJM costs by loss component (Dollars (Millions)): 2009 through 2013[31]

Year	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,862	3.1%

Total marginal loss costs for 2009 through 2013 are shown in Table 11-28 and Table 11-29. Table 11-28 shows PJM total marginal loss costs by accounting category for 2009 through 2013. Table 11-29 shows PJM total marginal loss costs by accounting category by market for 2009 through 2013.

Table 11-28 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2013

	Marginal Loss Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($77.8)	($1,313.6)	$32.0	($0.0)	$1,267.7
2010	($118.9)	($1,703.6)	$50.4	($0.0)	$1,635.0
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3

Table 11-29 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.9	($2.0)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$27.4	$12.5	($45.4)	($30.6)	($0.0)	$1,635.0
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.7	$33.0	$29.1	($106.3)	($102.4)	($0.0)	$1,035.3

31 The loss costs include net inadvertent charges.

Monthly Marginal Loss Costs

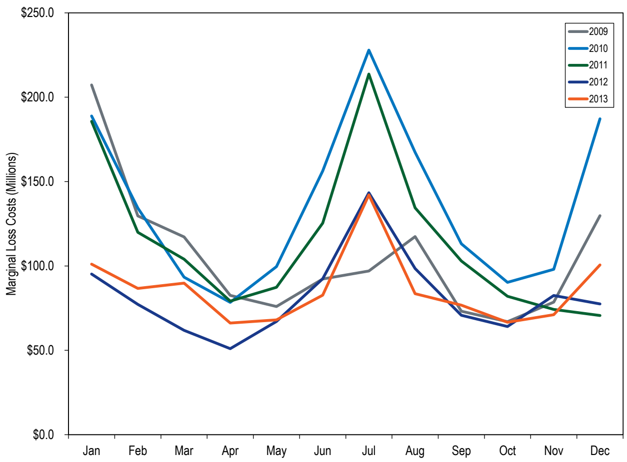
Table 11-30 shows a monthly summary of marginal loss costs by market type for 2012 and 2013.

Table 11-30 Monthly marginal loss costs by market (Dollars (Millions)): 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Apr	$55.4	($4.4)	$0.0	$51.0	$77.7	($11.5)	($0.0)	$66.2
May	$69.6	($2.5)	($0.0)	$67.1	$80.5	($12.4)	($0.0)	$68.1
Jun	$93.3	($0.8)	$0.0	$92.5	$91.7	($9.0)	($0.0)	$82.7
Jul	$141.8	$1.6	$0.0	$143.4	$149.2	($7.1)	($0.0)	$142.1
Aug	$96.1	$2.4	$0.0	$98.5	$91.3	($7.8)	($0.0)	$83.6
Sep	$71.7	($0.9)	($0.0)	$70.8	$85.0	($8.2)	($0.0)	$76.8
Oct	$65.9	($1.8)	$0.0	$64.2	$76.1	($9.5)	($0.0)	$66.7
Nov	$83.0	($0.6)	$0.0	$82.5	$79.3	($8.3)	($0.0)	$71.1
Dec	$78.8	($1.3)	($0.0)	$77.5	$110.7	($10.1)	($0.0)	$100.6
Total	$1,003.8	($22.1)	$0.0	$981.7	$1,137.7	($102.4)	($0.0)	$1,035.3

Figure 11-3 shows PJM monthly marginal loss costs for January 2009 through December 2013.

Figure 11-3 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through December of 2013



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 (generation energy credits less load energy payments) 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 11-31 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2013. The total marginal loss credits decreased $55.7 million in 2013 from 2012.

Table 11-31 Marginal loss credits (Dollars (Millions)): 2009 through 2013[32]

	Loss Credit Accounting (Millions)			
Year	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,635.0	($0.5)	$836.6
2011	($793.8)	$1,379.5	$0.9	$586.7
2012	($593.0)	$981.7	($2.0)	$386.7
2013	($701.5)	$1,035.3	($2.9)	$330.9

32 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.

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.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. (Decrement bids and energy sales are equivalent to demand.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. (Increment offers and energy purchases are equivalent to generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Explicit Energy Costs.** Explicit energy costs are the net energy costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy costs will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.
- **Inadvertent Energy Charges.** Inadvertent energy charges are the net energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, which are distributed on a load ratio basis.[33]

The total energy cost for 2013 was -$701.5 million, which was comprised of load energy payments of $42,773.8 million, generation energy credits of $43,467.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$7.5 million. The monthly energy costs for 2013 ranged from -$90.8 million in July to -$44.3 million in October.

33 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

Total Energy Costs

Table 11-32 shows total energy component costs and total PJM billing, for 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

Table 11-32 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2013[34]

Year	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($629)	NA	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($702)	18.3%	$33,862	(2.1%)

Energy costs for 2009 through 2013 are shown in Table 11-33 and Table 11-34. Table 11-33 shows PJM energy costs by accounting category for 2009 through 2013 and Table 11-34 shows PJM energy costs by market category for 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-32.

Table 11-33 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2013

	Energy Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,773.8	$43,467.8	$0.0	($7.5)	($701.5)

Table 11-34 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,794.6	$43,628.8	$0.0	($834.2)	($20.9)	($161.0)	$0.0	$140.1	($7.5)	($701.5)

34 The energy costs include net inadvertent charges.

Monthly Energy Costs

Table 11-35 shows a monthly summary of energy costs by market type for 2012 and 2013.

Table 11-35 Monthly energy costs by market type (Dollars (Millions)): 2012 and 2013

	Energy Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.0)
Apr	($30.7)	($2.8)	$0.7	($32.8)	($46.8)	$0.9	($0.6)	($46.5)
May	($39.4)	$0.0	($0.3)	($39.7)	($48.3)	($3.4)	($0.3)	($52.0)
Jun	($57.1)	$4.0	$0.0	($53.1)	($63.4)	$7.8	($0.6)	($56.2)
Jul	($84.0)	$3.0	$0.6	($80.4)	($111.1)	$21.4	($1.1)	($90.8)
Aug	($60.3)	$2.6	$0.3	($57.4)	($71.0)	$17.4	($0.7)	($54.3)
Sep	($43.6)	$1.1	($0.2)	($42.8)	($67.3)	$18.3	($0.9)	($49.9)
Oct	($42.2)	$1.6	$0.2	($40.5)	($64.0)	$20.5	($0.8)	($44.3)
Nov	($65.2)	$7.8	$1.1	($56.2)	($71.7)	$19.2	($1.1)	($53.7)
Dec	($72.7)	$19.0	($0.1)	($53.8)	($96.9)	$22.2	($1.3)	($76.0)
Total	($609.9)	$7.7	$9.1	($593.0)	($834.2)	$140.1	($7.5)	($701.5)

Figure 11-4 shows PJM monthly energy costs of January 2009 through December 2013.

Figure 11-4 PJM monthly energy costs (Dollars (Millions)): January 2009 through December 2013