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 price of energy for the system, given the current dispatch, at the load weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load weighted reference bus. The load weighted reference bus is not a fixed location but is dependent on the distribution of load at system load buses.

CLMP is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load weighted reference bus. In an unconstrained system CLMPS will be zero.

MLMP is the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. 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.[2]

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. 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.[3] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

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.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,255.3 million or 185.5 percent, from $676.9 million in 2013 to $1,932.2 million in 2014.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,220.0 million or 120.6 percent, from $1,011.3 million in 2013 to $2,231.3 million in 2014.
- **Balancing Congestion.** Balancing congestion costs increased by $35.3 million or 10.6 percent, from -$334.4 million in 2013 to -$299.1 million in 2014.
- **Real-Time Congestion.** Real-time congestion costs increased by $1,246.4 million or 131.8 percent, from $945.9 million in 2013 to $2,192.3 million in 2014.

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 2014.

2 See 2014 SOM Technical Appendices for a full discussion of the relationship between marginal, average and total losses.

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 18, 2015, and are subject to change, based on continued PJM billing updates.

- **Monthly Congestion.** In 2014, 42.7 percent ($825.1 million) of total congestion cost was incurred in January and 21.3 percent ($411.0 million) of total congestion cost was incurred in the months of February and March. Monthly total congestion costs in 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 Market in 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 1.1 percent from 359,581 congestion event hours in 2013 to 363,452 congestion event hours in 2014.

  Real-time congestion frequency increased by 49.0 percent from 19,325 congestion event hours in 2013 to 28,796 congestion event hours in 2014.

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

  The AP South Interface was the largest contributor to congestion costs in 2014. With $486.8 million in total congestion costs, it accounted for 25.2 percent of the total PJM congestion costs in 2014.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in 2014. AEP had $454.0 million in total congestion costs, comprised of -$756.6 million in total load congestion payments, -$1,269.4 million in total generation congestion credits and -$58.8 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 $299.8 million, or 66.0 percent of the total AEP control zone congestion costs.

- **Ownership.** In 2014, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In 2014, financial entities received $231.2 million in congestion credits, an increase of $131.9 million or 132.8 percent compared to 2013. In 2014, physical entities paid $2,163.3 million in congestion charges, an increase of $1,387.2 million or 178.7 percent compared to 2013.UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2014, the total explicit cost is -$169.0 million and 118.5 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$200.2 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $430.8 million or 41.6 percent, from $1,035.3 million in 2013 to $1,466.1 million in 2014. Total marginal loss costs increased because of the distribution of high load and outages caused by cold weather in January. The loss MW in PJM decreased 1.4 percent, from 17,389 GWh in 2013 to 17,150 GWh in 2014. The loss component of LMP remained constant, $0.02 in 2013 and $0.02 in 2014.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and outage patterns, and associated changes in the dispatch of generation. Monthly total marginal loss costs in 2014 ranged from $64.3 million in October to $414.6 million in January.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $433.7 million or 38.1 percent, from $1,137.8 million in 2013 to $1,571.4 million in 2014.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $2.8 million or 2.8 percent, from -$102.5 million in 2013 to -$105.3 million in 2014.

- **Marginal Loss Credits.** The marginal loss credits increased in 2014 by $143.6 million or 41.7 percent, from $344.8 million in 2013, to $488.4 million in 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $290.1 million or 42.2 percent, from -$687.6 million in 2013 to -$977.7 million in 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $510.0 million or 61.2 percent, from -$833.7 million in 2013 to -$1,343.7 million in 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $216.7 million or 141.2 percent, from $153.5 million in 2013 to $370.2 million in 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2014 ranged from -$272.7 million in January to -$39.1 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 and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion for the first seven months of the 2014 to 2015 planning period. ARR and FTR revenues offset 90.8 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 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.

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.[5] 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.[6] 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.

5 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <*http://www/monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf*>.

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

Table 11-1 shows the PJM real-time, load-weighted average LMP components 2009 to 2014.[7]

The load-weighted average real-time LMP increased $14.47 or 37.4 percent from $38.66 in 2013 to $53.14 in 2014. The load-weighted average congestion component decreased $0.02 or 303.5 percent from $0.01 in 2013 to -$0.02 in 2014. The load-weighted average loss component ($0.02) did not change in 2014 from 2013. The load-weighted average energy component increased $14.49 or 37.5 percent from $38.64 in 2013 to $53.13 in 2014.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2014[8]

	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
2014	$53.14	$53.13	($0.02)	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2014.[9]

The load-weighted average day-ahead LMP increased $14.69 or 37.8 percent from $38.93 in 2013 to $53.62 in 2014. The load-weighted average congestion component increased $0.12 or 90.6 percent from $0.13 in 2013 to $0.26 2014. The load-weighted average loss component decreased $0.02 or 912.6 percent from $0.00 in 2013 to -$0.02 in 2014. The load-weighted average energy component increased $14.59 or 37.6 percent from $38.79 in 2013 to $53.38 in 2014.

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

	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
2014	$53.62	$53.38	$0.26	($0.02)

7 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the Real-Time Energy Market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP.

8 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.

9 In the Real-Time Energy Market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP (SMP) and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for 2013 and 2014. In 2014, BGE had the highest congestion component of all control zones. ComEd had the lowest congestion component.

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

	2013				2014			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.11	$39.14	$0.27	$1.70	$55.77	$51.69	$2.11	$1.97
AEP	$35.56	$38.25	($1.78)	($0.92)	$47.81	$53.32	($4.32)	($1.19)
AP	$37.70	$38.39	($0.57)	($0.11)	$52.94	$53.88	($1.01)	$0.07
ATSI	$42.12	$38.43	$3.27	$0.42	$48.60	$52.07	($4.04)	$0.57
BGE	$43.52	$38.97	$2.79	$1.76	$67.78	$54.46	$10.86	$2.46
ComEd	$33.28	$38.65	($3.48)	($1.90)	$42.04	$51.56	($6.92)	($2.60)
DAY	$36.15	$38.61	($2.35)	($0.11)	$47.36	$53.07	($5.87)	$0.17
DEOK	$34.35	$38.57	($2.31)	($1.91)	$45.00	$52.87	($5.42)	($2.44)
DLCO	$35.70	$38.51	($1.61)	($1.20)	$44.22	$52.00	($6.12)	($1.66)
Dominion	$40.63	$38.84	$1.46	$0.33	$62.99	$54.58	$7.93	$0.48
DPL	$42.18	$38.96	$1.29	$1.93	$65.03	$54.72	$7.24	$3.07
EKPC	$33.96	$38.72	($2.73)	($2.02)	$47.88	$56.97	($6.57)	($2.52)
JCPL	$42.98	$39.54	$1.63	$1.81	$56.07	$52.18	$1.85	$2.04
Met-Ed	$39.72	$38.63	$0.34	$0.75	$56.08	$53.42	$1.55	$1.11
PECO	$39.70	$38.77	($0.11)	$1.03	$55.94	$52.73	$1.86	$1.35
PENELEC	$38.71	$38.18	($0.10)	$0.63	$51.90	$52.71	($1.31)	$0.50
Pepco	$42.78	$38.98	$2.62	$1.18	$65.61	$53.92	$10.09	$1.60
PPL	$39.26	$38.44	$0.18	$0.64	$56.97	$54.02	$2.03	$0.91
PSEG	$43.97	$38.93	$3.37	$1.67	$57.90	$51.43	$4.49	$1.99
RECO	$45.81	$39.65	$4.53	$1.63	$56.79	$51.34	$3.58	$1.87
PJM	$38.66	$38.64	$0.01	$0.02	$53.14	$53.13	($0.02)	$0.02

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

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

	2013				2014			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$41.48	$39.23	$0.61	$1.64	$57.24	$51.67	$4.04	$1.53
AEP	$36.44	$38.58	($1.26)	($0.88)	$48.83	$54.40	($4.59)	($0.98)
AP	$38.23	$38.62	($0.21)	($0.18)	$52.60	$54.21	($1.36)	($0.26)
ATSI	$38.13	$38.69	($0.85)	$0.29	$49.52	$52.63	($3.58)	$0.47
BGE	$44.32	$39.17	$3.46	$1.69	$68.52	$54.65	$11.97	$1.90
ComEd	$34.12	$38.86	($3.04)	($1.70)	$42.82	$52.38	($7.86)	($1.71)
DAY	$37.13	$38.89	($1.58)	($0.18)	$48.95	$53.95	($5.45)	$0.45
DEOK	$35.46	$38.70	($1.54)	($1.69)	$46.19	$52.68	($4.71)	($1.77)
DLCO	$36.35	$38.75	($1.17)	($1.22)	$44.95	$52.32	($5.52)	($1.85)
Dominion	$41.34	$39.15	$2.03	$0.16	$60.43	$54.75	$5.64	$0.05
DPL	$42.55	$39.10	$1.56	$1.89	$66.60	$54.56	$9.51	$2.52
EKPC	$35.65	$39.37	($1.68)	($2.04)	$48.80	$57.51	($6.32)	($2.39)
JCPL	$42.86	$39.48	$1.66	$1.73	$59.42	$52.87	$4.67	$1.87
Met-Ed	$40.04	$38.62	$0.83	$0.59	$57.42	$53.10	$3.71	$0.61
PECO	$40.14	$38.87	$0.32	$0.94	$57.60	$52.75	$3.87	$0.99
PENELEC	$39.29	$38.14	$0.38	$0.77	$51.32	$51.08	($0.21)	$0.44
Pepco	$43.16	$38.70	$3.33	$1.14	$64.04	$53.04	$9.85	$1.14
PPL	$39.67	$38.55	$0.65	$0.46	$59.04	$54.13	$4.47	$0.44
PSEG	$44.65	$39.17	$3.78	$1.70	$61.27	$52.09	$7.33	$1.84
RECO	$45.55	$39.37	$4.55	$1.62	$59.75	$51.71	$6.27	$1.76
PJM	$38.93	$38.79	$0.13	$0.00	$53.62	$53.38	$0.26	($0.02)

Hub Components

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

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

	2013				2014			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.63	$38.12	($2.34)	($2.15)	$43.51	$53.25	($6.46)	($3.28)
AEP-DAY Hub	$35.26	$38.28	($1.99)	($1.03)	$46.29	$53.41	($5.69)	($1.43)
ATSI Gen Hub	$40.52	$37.74	$2.96	($0.18)	$47.22	$51.92	($4.47)	($0.23)
Chicago Gen Hub	$31.74	$37.84	($3.72)	($2.38)	$39.52	$50.46	($7.68)	($3.25)
Chicago Hub	$33.79	$39.07	($3.44)	($1.83)	$42.68	$52.35	($7.11)	($2.56)
Dominion Hub	$40.89	$39.65	$1.33	($0.08)	$64.29	$56.55	$7.84	($0.10)
Eastern Hub	$41.24	$38.01	$1.28	$1.94	$61.27	$52.20	$6.29	$2.78
N Illinois Hub	$32.69	$38.24	($3.50)	($2.06)	$41.20	$51.02	($6.98)	($2.84)
New Jersey Hub	$43.33	$39.21	$2.43	$1.69	$56.21	$51.22	$3.05	$1.94
Ohio Hub	$35.26	$38.31	($2.12)	($0.94)	$46.25	$53.32	($5.80)	($1.28)
West Interface Hub	$37.29	$37.51	$0.34	($0.57)	$50.60	$51.86	($0.42)	($0.83)
Western Hub	$40.14	$39.37	$0.60	$0.17	$57.23	$55.07	$2.14	$0.02

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

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

	2013				2014			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.75	$37.24	($1.60)	($1.89)	$42.22	$48.97	($4.25)	($2.50)
AEP-DAY Hub	$35.67	$37.84	($1.27)	($0.90)	$46.64	$52.38	($4.83)	($0.91)
ATSI Gen Hub	$35.59	$36.30	($0.65)	($0.06)	$50.09	$52.42	($2.47)	$0.14
Chicago Gen Hub	$32.37	$37.73	($3.28)	($2.07)	$43.01	$55.95	($10.23)	($2.71)
Chicago Hub	$33.36	$37.86	($2.91)	($1.59)	$42.50	$51.94	($7.85)	($1.58)
Dominion Hub	$40.94	$39.19	$1.94	($0.19)	$59.15	$54.48	$5.14	($0.47)
Eastern Hub	$42.32	$38.73	$1.54	$2.05	$64.43	$53.17	$8.65	$2.61
N Illinois Hub	$33.13	$38.04	($3.11)	($1.80)	$42.47	$52.94	($8.44)	($2.02)
New Jersey Hub	$43.18	$38.91	$2.62	$1.64	$59.41	$51.99	$5.66	$1.77
Ohio Hub	$35.91	$37.95	($1.25)	($0.79)	$46.59	$52.22	($4.97)	($0.66)
West Interface Hub	$40.23	$40.67	$0.04	($0.48)	$49.78	$50.56	($0.05)	($0.72)
Western Hub	$39.77	$38.28	$1.24	$0.25	$52.65	$50.52	$2.31	($0.18)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2014. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs increased because of the distribution of high load and outages caused by cold weather in January.

Table 11-7 Total PJM costs by component (Dollars (Millions)): 2009 through 2014[10 11]

	Component Costs (Millions)					
	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	($688)	$1,035	$677	$1,025	$33,862	3.0%
2014	($978)	$1,466	$1,932	$2,421	$50,030	4.8%

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

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 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

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.

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

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). 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 2014 were $1,932.2 million, which was comprised of load congestion payments of $648.1 million, generation credits of -$1,453.0 million and explicit congestion of -$169.0 million. 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.

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.

Total Congestion

Table 11-8 shows total congestion by year from 2008 through 2014. 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.[17 18]

Table 11-8 Total PJM congestion (Dollars (Millions)): 2008 to 2014

	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%
2014	$1,932.2	185.5%	$50,030	3.9%

Table 11-9 shows the congestion costs by accounting category for 2014. In 2014, PJM total congestion costs were comprised of $648.1 million in load congestion payments, -$1,453.0 million in generation congestion credits, and -$169.0 million in explicit congestion costs.

Table 11-10 and Table 11-11 show that the increase in total congestion cost from 2013 to 2014 is mainly due to the increase in negative generation credits incurred by generation in day-ahead market. Congestion costs incurred by generation in day-ahead market increased by $1,299.3 million or 163.5 percent, from $794.7 million in 2013 to $2,094.0 million in 2014.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 to 2014

	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
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)) 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$79.9	$0.0	$0.0	$79.9	($57.8)	$0.0	$0.0	($57.8)	$0.0	$22.2
Demand	$130.2	$0.0	$0.0	$130.2	$142.4	$0.0	$0.0	$142.4	$0.0	$272.6
Demand Response	($1.1)	$0.0	$0.0	($1.1)	$1.0	$0.0	$0.0	$1.0	($0.0)	($0.1)
Explicit Congestion Only	$0.0	$0.0	$3.2	$3.2	$0.0	$0.0	$0.3	$0.3	$0.0	$3.5
Export	($95.0)	$0.0	($0.8)	($95.7)	($44.2)	$0.0	$6.3	($37.9)	$0.0	($133.6)
Generation	$0.0	($2,094.0)	$0.0	$2,094.0	$0.0	$296.4	$0.0	($296.4)	$0.0	$1,797.6
Grandfathered Overuse	$0.0	$0.0	($11.4)	($11.4)	$0.0	$0.0	$0.9	$0.9	$0.0	($10.5)
Import	$0.0	($46.8)	$8.6	$55.4	$0.0	($125.1)	$3.8	$128.9	$0.0	$184.3
INC	$0.0	($12.7)	$0.0	$12.7	$0.0	$35.7	$0.0	($35.7)	$0.0	($23.0)
Internal Bilateral	$418.1	$419.0	$0.9	$0.0	$13.4	$13.4	$0.0	($0.0)	$0.0	$0.0
Upto Congestion	$0.0	$0.0	($57.0)	($57.0)	$0.0	$0.0	($143.2)	($143.2)	$0.0	($200.2)
Wheel In	$0.0	$63.2	$21.2	($42.1)	$0.0	($2.2)	($1.7)	$0.5	$0.0	($41.6)
Wheel Out	$63.2	$0.0	$0.0	$63.2	($2.2)	$0.0	$0.0	($2.2)	$0.0	$61.1
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

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 January 16, 2015).

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 35.12.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 16, 2015).

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)) 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$52.8	$0.0	$0.0	$52.8	($51.1)	$0.0	$0.0	($51.1)	$0.0	$1.8
Demand	$56.7	$0.0	$0.0	$56.7	$68.4	$0.0	$0.0	$68.4	$0.0	$125.1
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)
Export	($41.0)	$0.0	($0.6)	($41.6)	($14.9)	$0.0	$2.7	($12.3)	$0.0	($53.9)
Generation	$0.0	($794.7)	$0.0	$794.7	$0.0	$146.7	$0.0	($146.7)	$0.0	$647.9
Grandfathered Overuse	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.2)
Import	$0.0	($15.0)	$3.8	$18.8	$0.0	($47.2)	$1.2	$48.4	$0.0	$67.2
INC	$0.0	$3.8	$0.0	($3.8)	$0.0	$28.0	$0.0	($28.0)	$0.0	($31.8)
Internal Bilateral	$169.3	$169.8	$0.5	$0.0	$5.2	$5.2	$0.0	$0.0	$0.0	$0.0
Upto Congestion	$0.0	$0.0	$125.2	$125.2	$0.0	$0.0	($212.7)	($212.7)	$0.0	($87.5)
Wheel In	$0.0	$43.6	$8.9	($34.8)	$0.0	($1.7)	($0.3)	$1.4	$0.0	($33.3)
Wheel Out	$43.6	$0.0	$0.0	$43.6	($1.7)	$0.0	$0.0	($1.7)	$0.0	$41.9
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.1	($209.2)	($334.4)	$0.0	$676.9

Monthly Congestion

Table 11-12 shows that monthly total congestion costs ranged from $54.3 million to $825.1 million in 2014. Table 11-12 shows that congestions costs in January of 2014 were substantially higher than congestion costs in January of 2013, due to weather related load and outages in January of 2014.

Table 11-12 Monthly PJM congestion costs by market (Dollars (Millions)): 2013 to 2014

	Congestion Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	InadvertentCharges	Grand Total	Day-Ahead Total	Balancing Total	InadvertentCharges	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	($61.5)	$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
Oct	$54.6	($13.3)	($0.0)	$41.4	$87.1	($14.3)	($0.0)	$72.8
Nov	$59.3	($18.1)	($0.0)	$41.2	$105.3	($16.3)	$0.0	$89.0
Dec	$95.9	($11.2)	$0.0	$84.7	$74.3	($9.3)	($0.0)	$65.0
Total	$1,011.3	($334.4)	$0.0	$676.9	$2,231.3	($299.1)	$0.0	$1,932.2

Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2014.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 to2014

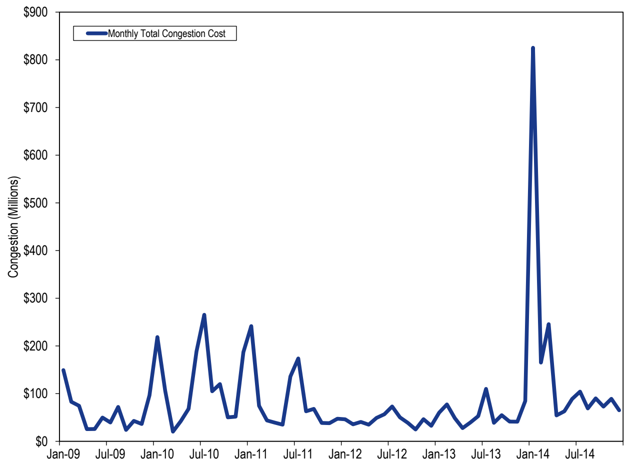


Table 11-13 shows the monthly total congestion costs for each virtual transaction type in 2014 and Table 11-14 shows the monthly total congestion costs for each virtual transaction type in 2013. Comparing Table 11-13 and Table 11-14 shows that UTCs paid day-ahead congestion charges in 2013 but were paid day ahead congestion credits in 2014. Total day-ahead congestion payments by UTCs decreased by $182.8 million from 2013 to 2014, dropping from $125.2 million in 2013 to -$57.0 million in 2014. Over the same period balancing congestion payments to UTCs decreased from $212.7 million in 2013 to $143.2 million in 2014. Overall, total congestion payments to UTC increased significantly between 2013 and 2014. UTCs were paid $87.5 million in congestion rents in 2013 and $200.2 million in 2014. UTCs were paid $132.9 million in January 2014 alone due to emergency conditions in that month. The significant reduction in UTC activity that started September 8, 2014, is reflected in the reduced day-ahead charges attributed to UTCs from September through December of 2014. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[19]

Table 11-13 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2014

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
	DEC	INC	Upto Congestion	Virtual Total	DEC	INC	Upto Congestion	Virtual Total	Virtual Grand Total
Jan	$51.0	$27.1	($109.4)	($31.4)	($31.8)	($26.7)	($23.5)	($82.0)	($113.3)
Feb	$7.4	$1.5	($5.8)	$3.1	($8.1)	($6.5)	($11.1)	($25.7)	($22.6)
Mar	$2.2	$4.9	$3.1	$10.2	($2.3)	($11.0)	($33.3)	($46.6)	($36.4)
Apr	($2.2)	($0.2)	$12.7	$10.3	$0.8	($0.3)	($9.5)	($9.0)	$1.3
May	$3.8	($1.6)	$10.7	$12.9	($3.5)	$0.4	($9.2)	($12.3)	$0.7
Jun	$2.7	($1.0)	$11.6	$13.2	($0.1)	($0.5)	($15.5)	($16.1)	($2.9)
Jul	$5.2	($0.1)	$13.4	$18.5	($4.3)	($1.2)	($13.7)	($19.2)	($0.7)
Aug	$1.4	($1.2)	$4.4	$4.6	($0.3)	$0.7	($1.1)	($0.7)	$3.9
Sep	$2.5	($2.6)	($1.1)	($1.2)	($0.6)	$1.0	$0.7	$1.0	($0.1)
Oct	$2.0	($6.2)	($0.1)	($4.3)	($1.5)	$5.3	($9.5)	($5.7)	($10.0)
Nov	$2.1	($5.3)	$1.0	($2.3)	($6.2)	$1.8	($10.8)	($15.1)	($17.4)
Dec	$1.9	($2.5)	$2.5	$1.9	$0.2	$1.3	($6.7)	($5.2)	($3.3)
Total	$79.9	$12.7	($57.0)	$35.6	($57.8)	($35.7)	($143.2)	($236.6)	($201.0)

19 See 18 CFR § 385.213 (2014).

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2013

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
	DEC	INC	Upto Congestion	Virtual Total	DEC	INC	Upto Congestion	Virtual Total	Virtual Grand Total
Jan	$8.3	($1.4)	$17.2	$24.1	($15.8)	($2.7)	($31.4)	($49.9)	($25.7)
Feb	$4.2	($0.2)	$14.5	$18.5	($5.3)	($1.3)	($21.0)	($27.7)	($9.1)
Mar	$2.8	($0.4)	$12.5	$14.9	($3.9)	($0.3)	($13.7)	($17.9)	($3.0)
Apr	$1.7	($0.4)	$6.6	$7.9	($2.3)	($0.4)	($9.4)	($12.1)	($4.2)
May	$4.0	($1.1)	$12.2	$15.2	($5.9)	$0.1	($30.2)	($36.0)	($20.8)
Jun	$4.8	$0.2	$18.4	$23.4	($5.8)	($2.5)	($17.7)	($26.0)	($2.6)
Jul	$6.9	$2.5	$17.7	$27.2	($4.7)	($7.7)	($23.7)	($36.1)	($8.9)
Aug	$3.4	$0.4	$7.1	$10.9	($2.6)	($1.3)	($7.3)	($11.1)	($0.2)
Sep	$4.9	($0.2)	$5.9	$10.5	$10.8	($11.4)	($34.7)	($35.3)	($24.8)
Oct	$0.7	($0.9)	$8.2	$8.0	($1.7)	($0.7)	($10.1)	($12.5)	($4.5)
Nov	$3.2	($0.8)	$4.8	$7.2	($5.3)	($1.1)	($10.4)	($16.8)	($9.6)
Dec	$8.0	($1.6)	$0.1	$6.6	($8.7)	$1.2	($3.0)	($10.5)	($4.0)
Total	$52.8	($3.8)	$125.2	$174.3	($51.1)	($28.0)	($212.7)	($291.8)	($117.5)

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 2014, there were 363,452 day-ahead, congestion-event hours compared to 359,581 day-ahead congestion-event hours in 2013. In 2014, there were 28,796 real-time, congestion-event hours compared to 19,325 real-time, congestion-event hours in 2013.

During 2014, there were 12,323 real-time congestion hours, 3.4 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During 2014, there were 12,804 day-ahead congestion hours, 44.5 percent of real-time congestion hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to total congestion costs in 2014. With $486.8 million in total congestion costs, it accounted for 25.2 percent of the total PJM congestion costs in 2014. The top five constraints in terms of congestion costs contributed $953.6 million, or 49.4 percent, of the total PJM congestion costs in 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 2014, day-ahead, congestion-event hours increased on all types of facilities except transmission lines compared to 2013. Real-time, congestion-event hours increased on all types of facilities.

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

Table 11-15 provides congestion-event hour subtotals and congestion cost subtotals comparing 2014 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[20] [21] Table 11-16 presents this information for 2013.

Table 11-17 and Table 11-18 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 11-17. In 2014, there were 363,452 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 12,323 (3.4 percent) were also constrained in the Real-Time Energy Market. In 2013, among the 359,581 day-ahead congestion event hours, only 8,093 (2.3 percent) were binding in the Real-Time Energy Market.[22]

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 11-18. In 2014, there were 28,796 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 12,804 (44.5 percent) were also constrained in the Day-Ahead Energy Market. In 2013, among the 19,325 real-time congestion event hours, only 8,189 (42.4 percent) were also in the Day-Ahead Energy Market.

Table 11-15 Congestion summary (By facility type): 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	($100.8)	($423.8)	($16.8)	$306.2	$2.8	$13.7	($37.9)	($48.7)	$257.4	35,828	5,909
Interface	$367.3	($630.9)	($105.2)	$893.1	$62.7	$145.7	$16.6	($66.5)	$826.6	19,248	5,511
Line	$215.7	($470.6)	$39.9	$726.2	($25.8)	$41.9	($59.1)	($126.8)	$599.5	189,008	14,687
Other	$0.0	($2.5)	$1.0	$3.6	$0.0	$0.0	($0.0)	$0.0	$3.6	7,003	1
Transformer	$111.2	($131.4)	$32.3	$275.0	$5.3	$15.3	($62.2)	($72.2)	$202.8	112,365	2,688
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.5	$9.0	$15.1	$42.4	NA	NA
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,452	28,796

Table 11-16 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	($51.7)	($185.7)	$19.6	$153.7	$0.9	$12.3	($40.1)	($51.4)	$102.3	33,555	5,711
Interface	$180.7	($95.3)	$15.7	$291.6	$23.6	$36.6	($36.1)	($49.1)	$242.5	15,625	1,745
Line	$86.2	($264.4)	$62.2	$412.8	($21.4)	$68.9	($107.0)	($197.3)	$215.5	198,110	10,024
Other	$10.9	($0.3)	$6.8	$18.0	($0.3)	$0.2	($3.8)	($4.3)	$13.7	10,883	162
Transformer	$29.0	($63.6)	$25.6	$118.2	$2.4	$11.1	($23.2)	($31.8)	$86.4	101,408	1,683
Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.4)	$16.4	NA	NA
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	359,581	19,325

20 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.

21 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

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.

Table 11-17 Congestion event hours (Day-Ahead against Real-Time): 2013 to 2014

	Congestion Event Hours					
	2013			2014		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	33,555	2,452	7.3%	35,828	3,265	9.1%
Interface	15,625	1,298	8.3%	19,248	1,355	7.0%
Line	198,110	3,507	1.8%	189,008	6,713	3.6%
Other	10,883	171	1.6%	7,003	0	0.0%
Transformer	101,408	665	0.7%	112,365	990	0.9%
Total	359,581	8,093	2.3%	363,452	12,323	3.4%

Table 11-18 Congestion event hours (Real-Time against Day-Ahead): 2013 to 2014

	Congestion Event Hours					
	2013			2014		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,711	2,587	45.3%	5,909	3,395	57.5%
Interface	1,745	1,384	79.3%	5,511	1,722	31.2%
Line	10,024	3,450	34.4%	14,687	6,727	45.8%
Other	162	110	67.9%	1	0	0.0%
Transformer	1,683	658	39.1%	2,688	960	35.7%
Total	19,325	8,189	42.4%	28,796	12,804	44.5%

Table 11-19 shows congestion costs by facility voltage class for 2014. Congestion costs in 2014 decreased for facilities rated at 460 kV, 161 kV, 13 kV and 12 kV compared to 2013 (Table 11-20).

Table 11-19 Congestion summary (By facility voltage): 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	$24.5	($53.9)	$3.7	$82.2	$1.6	$0.4	($4.7)	($3.4)	$78.8	12,662	657
500	$378.4	($629.6)	($105.1)	$902.9	$75.0	$161.8	$7.6	($79.2)	$823.7	25,516	2,467
460	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	218	0
345	($54.2)	($386.7)	$7.0	$339.5	($0.3)	$20.3	($41.3)	($61.9)	$277.6	72,286	3,385
230	$145.6	($239.6)	($1.1)	$384.1	$3.4	($0.2)	($1.9)	$1.7	$385.8	56,532	8,293
161	($28.5)	($62.9)	($2.5)	$31.9	($1.9)	$0.6	($1.6)	($4.1)	$27.8	7,042	1,178
138	$48.9	($281.5)	$43.2	$373.7	($3.1)	$40.5	($96.3)	($139.9)	$233.8	146,407	9,404
115	$3.3	($23.1)	$4.6	$30.9	($6.1)	$2.7	($3.4)	($12.2)	$18.8	19,474	1,299
69	$75.3	$18.3	$1.3	$58.2	($23.7)	($9.6)	($1.0)	($15.2)	$43.1	19,352	2,113
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
34	$0.0	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3,917	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	31	0
13	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	5	0
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	0	0
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$1,932.2	363,452	28,796

Table 11-20 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	10,430	22
500	$177.0	($105.8)	$19.1	$301.9	$29.0	$39.7	($49.3)	($60.0)	$241.9	20,509	2,144
345	($41.8)	($163.6)	$18.4	$140.2	($0.0)	$14.8	($49.9)	($64.8)	$75.4	58,964	3,919
230	$84.3	($148.0)	$39.7	$272.0	($2.9)	$52.1	($53.4)	($108.4)	$163.6	58,914	3,629
161	($9.9)	($20.5)	($0.8)	$9.8	($1.3)	$0.7	($3.7)	($5.6)	$4.2	3,700	1,075
138	($15.1)	($160.6)	$40.1	$185.6	($7.3)	$16.6	($48.8)	($72.7)	$112.9	158,914	6,416
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)	($10.3)	$17.0	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
35	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
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	($0.4)	$16.4	0	0
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	359,581	19,325

Constraint Duration

Table 11-21 lists the constraints in 2013 and 2014 that were most frequently binding and Table 11-22 shows the constraints which experienced the largest change in congestion-event hours from 2013 to 2014.

Table 11-21 Top 25 constraints with frequent occurrence: 2013 to 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	2,333	8,820	6,487	29	23	(6)	27%	100%	74%	0%	0%	(0%)
2	Tanners Creek	Transformer	6,846	8,096	1,250	0	0	0	78%	92%	14%	0%	0%	0%
3	Oak Grove - Galesburg	Flowgate	3,177	6,905	3,728	888	1,059	171	36%	79%	42%	10%	12%	2%
4	Braidwood	Transformer	8,252	7,742	(510)	0	0	0	94%	88%	(6%)	0%	0%	0%
5	Clinch River	Transformer	5,168	6,618	1,450	0	0	0	59%	75%	16%	0%	0%	0%
6	Bagley - Graceton	Line	2,087	4,584	2,497	440	1,884	1,444	24%	52%	28%	5%	21%	16%
7	AP South	Interface	6,330	5,090	(1,240)	1,138	981	(157)	72%	58%	(14%)	13%	11%	(2%)
8	Kendall Co. Energy Ctr.	Transformer	2,071	5,488	3,417	0	0	0	24%	62%	39%	0%	0%	0%
9	Wolf Creek	Transformer	1,779	5,102	3,323	48	131	83	20%	58%	38%	1%	1%	1%
10	East Bend	Transformer	2,197	5,082	2,885	0	0	0	25%	58%	33%	0%	0%	0%
11	Burlington - Croydon	Line	238	4,971	4,733	0	0	0	3%	57%	54%	0%	0%	0%
12	Monticello - East Winamac	Flowgate	2,041	3,511	1,470	554	1,440	886	23%	40%	17%	6%	16%	10%
13	Bergen - New Milford	Line	1,690	4,745	3,055	0	0	0	19%	54%	35%	0%	0%	0%
14	Mardela - Vienna	Line	3,747	4,627	880	213	76	(137)	43%	53%	10%	2%	1%	(2%)
15	Huntington Junction - Huntington	Line	3,011	4,508	1,497	0	0	0	34%	51%	17%	0%	0%	0%
16	Nelson - Cordova	Line	5,764	4,107	(1,657)	244	279	35	66%	47%	(19%)	3%	3%	0%
17	Breed - Wheatland	Flowgate	2,344	3,758	1,414	658	602	(56)	27%	43%	16%	8%	7%	(1%)
18	Sunbury	Transformer	6,866	4,344	(2,522)	0	0	0	78%	49%	(29%)	0%	0%	0%
19	Gould Street - Westport	Line	7,401	3,867	(3,534)	21	0	(21)	84%	44%	(40%)	0%	0%	(0%)
20	SENECA	Interface	0	3,562	3,562	0	0	0	0%	41%	41%	0%	0%	0%
21	Sporn	Transformer	8,676	3,560	(5,116)	0	0	0	99%	41%	(59%)	0%	0%	0%
22	Danville - East Danville	Line	2,982	3,523	541	13	0	(13)	34%	40%	6%	0%	0%	(0%)
23	Howard - Shelby	Line	5,489	3,445	(2,044)	0	0	0	63%	39%	(23%)	0%	0%	0%
24	Seneca	Interface	0	0	0	0	3,227	3,227	0%	0%	0%	0%	37%	37%
25	Fort Robinson - Wolf Hills	Line	1,738	3,185	1,447	0	0	0	20%	36%	16%	0%	0%	0%

Table 11-22 Top 25 constraints with largest year-to-year change in occurrence: 2013 to 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	2,333	8,820	6,487	29	23	(6)	27%	100%	74%	0%	0%	(0%)
2	Sporn	Transformer	8,676	3,560	(5,116)	0	0	0	99%	41%	(59%)	0%	0%	0%
3	Burlington - Croydon	Line	238	4,971	4,733	0	0	0	3%	57%	54%	0%	0%	0%
4	Bagley - Graceton	Line	2,087	4,584	2,497	440	1,884	1,444	24%	52%	28%	5%	21%	16%
5	Oak Grove - Galesburg	Flowgate	3,177	6,905	3,728	888	1,059	171	36%	79%	42%	10%	12%	2%
6	Readington - Roseland	Line	4,177	1,169	(3,008)	817	189	(628)	48%	13%	(34%)	9%	2%	(7%)
7	SENECA	Interface	0	3,562	3,562	0	0	0	0%	41%	41%	0%	0%	0%
8	Gould Street - Westport	Line	7,401	3,867	(3,534)	21	0	(21)	84%	44%	(40%)	0%	0%	(0%)
9	Kendall Co. Energy Ctr.	Transformer	2,071	5,488	3,417	0	0	0	24%	62%	39%	0%	0%	0%
10	Wolf Creek	Transformer	1,779	5,102	3,323	48	131	83	20%	58%	38%	1%	1%	1%
11	Seneca	Interface	0	0	0	0	3,227	3,227	0%	0%	0%	0%	37%	37%
12	Joshua Falls	Transformer	19	3,064	3,045	0	13	13	0%	35%	35%	0%	0%	0%
13	Bergen - New Milford	Line	1,690	4,745	3,055	0	0	0	19%	54%	35%	0%	0%	0%
14	Bridgewater - Middlesex	Line	3,046	223	(2,823)	257	31	(226)	35%	3%	(32%)	3%	0%	(3%)
15	Rocky Mount - Battleboro	Line	2,945	312	(2,633)	430	14	(416)	34%	4%	(30%)	5%	0%	(5%)
16	East Bend	Transformer	2,197	5,082	2,885	0	0	0	25%	58%	33%	0%	0%	0%
17	Haurd - Steward	Line	3,588	749	(2,839)	0	0	0	41%	9%	(32%)	0%	0%	0%
18	Sayreville - Sayreville	Line	44	2,869	2,825	0	0	0	1%	33%	32%	0%	0%	0%
19	Kenney - Stockton	Line	99	1,517	1,418	93	1,469	1,376	1%	17%	16%	1%	17%	16%
20	Cherry Valley	Transformer	12	2,420	2,408	8	252	244	0%	28%	27%	0%	3%	3%
21	Cook - Palisades	Flowgate	0	2,316	2,316	0	308	308	0%	26%	26%	0%	4%	4%
22	Zion	Line	3,018	488	(2,530)	0	0	0	34%	6%	(29%)	0%	0%	0%
23	Sunbury	Transformer	6,866	4,344	(2,522)	0	0	0	78%	49%	(29%)	0%	0%	0%
24	Keeney	Transformer	678	3,099	2,421	0	58	58	8%	35%	28%	0%	1%	1%
25	Electric Junction - Frontenac	Line	2,540	123	(2,417)	0	0	0	29%	1%	(28%)	0%	0%	0%

Constraint Costs

Table 11-23 and Table 11-24 present the top constraints affecting congestion costs by facility for the periods 2014 and 2013.

Table 11-23 Top 25 constraints affecting PJM congestion costs (By facility): 2014

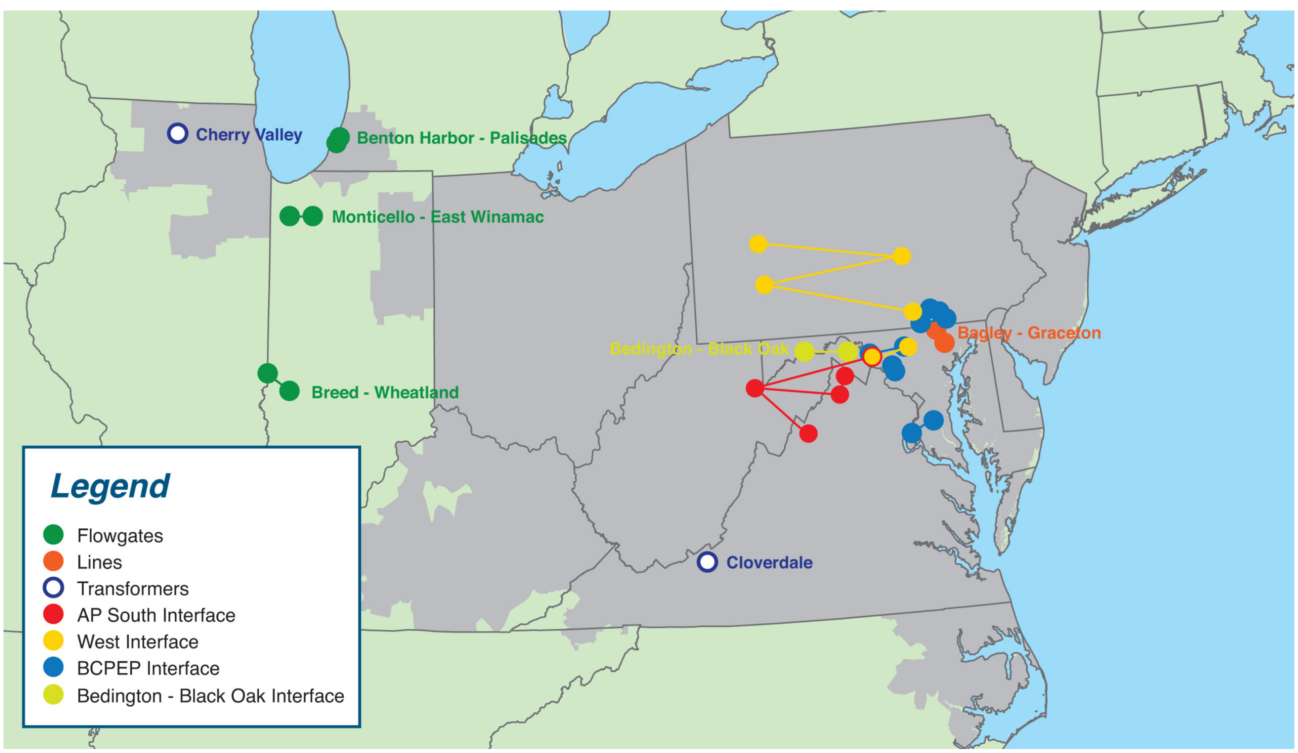
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2014
1	AP South	Interface	500	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	25.2%
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	9.4%
3	Bagley - Graceton	Line	BGE	$98.5	($9.5)	($1.7)	$106.3	$5.7	($4.0)	$4.5	$14.2	$120.5	6.2%
4	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	4.4%
5	Breed - Wheatland	Flowgate	MISO	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	4.1%
6	Benton Harbor - Palisades	Flowgate	MISO	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	2.9%
7	Cloverdale	Transformer	AEP	$23.3	($27.3)	$0.2	$50.7	$0.0	$0.0	$0.0	$0.0	$50.7	2.6%
8	BCPEP	Interface	Pepco	$15.6	($15.2)	($1.6)	$29.3	($1.6)	($14.2)	$1.5	$14.1	$43.4	2.2%
9	Unclassified	Unclassified	Unclassified	$2.0	($11.8)	$13.4	$27.3	$7.6	$1.6	$9.0	$15.1	$42.4	2.2%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.7%
11	Oak Grove - Galesburg	Flowgate	MISO	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	1.6%
12	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.5%
13	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.4%
14	Cloverdale	Transformer	AEP	$23.1	($4.8)	($2.3)	$25.7	$0.0	$0.0	$0.0	$0.0	$25.7	1.3%
15	Cherry Valley	Transformer	ComEd	$20.1	($16.5)	$4.3	$40.8	($4.4)	$2.6	($9.7)	($16.7)	$24.2	1.2%
16	Wolf Creek	Transformer	AEP	$4.6	$1.3	$4.7	$8.0	$3.6	$5.6	($29.3)	($31.3)	($23.3)	(1.2%)
17	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.2%
18	SENECA	Interface	PENELEC	$5.6	$9.9	($6.5)	($10.9)	($3.0)	$1.2	($6.1)	($10.4)	($21.3)	(1.1%)
19	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.1%
20	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1.1%
21	Bergen - New Milford	Line	PSEG	$22.0	$13.2	$12.0	$20.7	$0.0	$0.0	$0.0	$0.0	$20.7	1.1%
22	Nelson - Cordova	Line	ComEd	($24.7)	($47.1)	$4.2	$26.6	($0.7)	$1.1	($4.3)	($6.0)	$20.5	1.1%
23	Bridgewater - Middlesex	Line	PSEG	$0.2	($22.2)	($3.0)	$19.4	($1.5)	$0.1	$1.4	($0.2)	$19.2	1.0%
24	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	0.9%
25	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.8%

Table 11-24 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	$2.1	($0.4)	($2.4)	$22.5	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	2.8%
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	($0.4)	$16.5	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	$4.4	$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	($2.1)	($2.9)	$9.6	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	$1.8	($2.1)	($2.8)	$8.9	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%)

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

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: 2014



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

As of December 31, 2014, PJM had 102 flowgates eligible for M2M (Market to Market) coordination and MISO had 275 flowgates eligible for M2M coordination.

Table 11-25 and Table 11-26 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2014 and 2013, and which had the greatest congestion cost impact on PJM. 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 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 11-25 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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	($17.7)	($100.2)	($9.3)	$73.2	$2.4	$1.1	$5.6	$6.9	$80.1	3,758	602
2	Benton Harbor - Palisades	($12.5)	($79.3)	($8.0)	$58.8	($0.2)	$0.7	($1.0)	($1.8)	$57.0	3,025	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	Oak Grove - Galesburg	($28.4)	($62.2)	($2.3)	$31.5	($0.4)	$0.5	($0.3)	($1.3)	$30.3	6,905	1,059
5	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
6	Michigan City - Laporte	($4.8)	($17.2)	$1.9	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	3,111	0
7	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	115
8	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
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	Bunsonville - Eugene	($4.4)	($8.6)	($0.1)	$4.1	($0.1)	($0.2)	($0.9)	($0.7)	$3.4	2,244	675
12	Rantoul - Rantoul Jct	($2.7)	($5.5)	$0.3	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1,088	0
13	Batesville - Hubble	($1.7)	($5.6)	($0.9)	$2.9	($0.0)	($0.0)	$0.1	$0.1	$3.0	438	16
14	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
15	Byron - Cherry Valley	($0.6)	($3.4)	$0.1	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	42	0
16	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
17	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
18	Edwards - Kewanee	($1.7)	($3.9)	$0.1	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	1,864	0
19	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	169	19
20	Pana North	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.3	($2.0)	($2.3)	($1.9)	162	275

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (September 17, 2010), Section 6.1 <*http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx*> (Accessed February 25, 2015).

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (February 26, 2014), Section 2.2.24 <*http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx*> (Accessed February 25, 2015).

Table 11-26 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	($2.1)	($2.9)	$9.6	2,495	117
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	840
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 - Phipps 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

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.[25] 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.[26]

Table 11-27 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2014, and which had the greatest congestion cost impact on PJM.

Table 11-27 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 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	143
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 11-28 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

25 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 January 16, 2015).

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 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 16, 2015).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-29 and Table 11-30 show the 500 kV constraints affecting congestion costs in PJM for 2014 and 2013. 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.

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 11-29 Regional constraints summary (By facility): 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	$329.7	($201.4)	($11.2)	$520.0	$31.5	$73.5	$8.9	($33.1)	$486.8	5,090	981
2	West	Interface	500	($21.3)	($297.0)	($79.1)	$196.5	$17.7	$49.7	$17.0	($15.0)	$181.6	1,534	415
3	Bedington - Black Oak	Interface	500	$42.8	($43.9)	($0.2)	$86.5	$3.9	$3.4	($2.3)	($1.9)	$84.6	2,796	323
4	East	Interface	500	($9.8)	($34.2)	($3.4)	$21.0	$0.3	$0.7	$0.5	$0.1	$21.1	1,734	17
5	5004/5005 Interface	Interface	500	($0.7)	($23.6)	($3.3)	$19.5	$8.1	$17.5	$7.3	($2.1)	$17.4	554	336
6	SENECA	Interface	500	$5.6	$9.9	($6.5)	($10.9)	$0.0	$0.0	$0.0	$0.0	($10.9)	3,562	0
7	AEP - DOM	Interface	500	$10.7	($11.4)	$3.9	$26.0	$5.3	$13.2	($9.6)	($17.5)	$8.5	2,511	66
8	Central	Interface	500	($5.2)	($13.9)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.6	334	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
11	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	53	0
12	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	1

Table 11-30 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 11-31 Congestion cost by type of participant: 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	$65.7	$73.9	($78.2)	($86.5)	($43.2)	($10.6)	($112.0)	($144.7)	$0.0	($231.2)
Physical	$529.8	($1,745.1)	$42.8	$2,317.8	$95.9	$228.7	($21.6)	($154.4)	$0.0	$2,163.3
Total	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2

Table 11-32 Congestion cost by type of participant: 2013

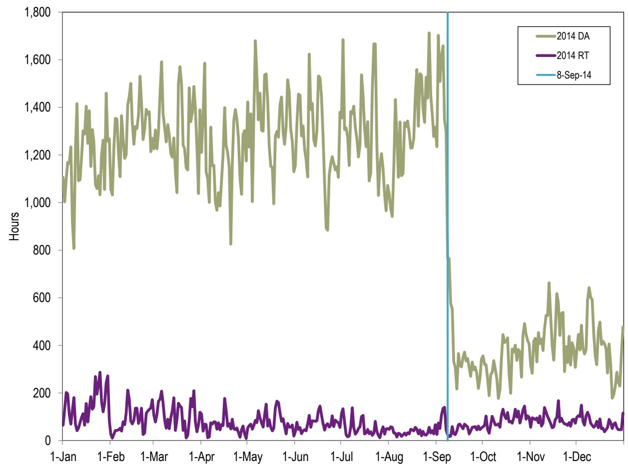
	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$53.1	$45.3	$84.3	$92.1	($33.9)	$1.5	($156.0)	($191.4)	$0.0	($99.3)
Physical	$228.0	($637.9)	$53.2	$919.1	$39.8	$129.8	($53.0)	($143.0)	$0.0	$776.1
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9

In 2014, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. UTCs are in the explicit cost category and comprise most of that category. Total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2014, the total explicit cost was -$169.0 million (indicating net credits to participants), of which -$200.2 million (118.5 percent) was credited to UTCs. In 2014, financial entities received $231.2 million in net congestion credits, an increase of $131.9 million or 132.8 percent compared to 2013. In 2014, physical entities paid $2,163.3 million in congestion charges, an increase of $1,387.2 million or 178.7 percent compared to 2013.

Congestion-Event Summary before and after September 8, 2014

The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[27] Figure 11-3 shows the daily day-ahead and real-time congestion event hours for 2014.

Figure 11-3 Daily congestion event hours: 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.

27 See 18 CFR § 385.213 (2014).

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.[28] 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 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 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 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

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

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.[29]

The total marginal loss cost in PJM for 2014 was $1,466.1 million, which was comprised of load loss payments of -$59.2 million, generation loss credits of -$1,581.3 million, explicit loss costs of -$56.0 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in 2014 ranged from $64.3 million in October to $414.6 million in January. Marginal loss credits increased in 2014 by $143.6 million or 41.7 percent from 2013, from $344.8 million to $488.4 million.

Total Marginal Loss Costs

Table 11-33 shows the total marginal loss component costs for 2009 through 2014.

Table 11-33 Total marginal loss component costs (Dollars (Millions)): 2009 through 2014[30]

	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%
2014	$1,466	41.6%	$50,030	2.9%

Total marginal loss costs for 2009 through 2014 are shown in Table 11-34 and Table 11-35. Table 11-34 shows PJM total marginal loss costs by accounting category for 2009 through 2014. Table 11-35 shows PJM total marginal loss costs by accounting category by market for 2009 through 2014.

Table 11-34 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2014

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
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
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1

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

30 The loss costs include net inadvertent charges.

Table 11-35 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2014

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
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	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1

Table 11-36 Monthly marginal loss costs by market (Dollars (Millions)): 2013 and 2014

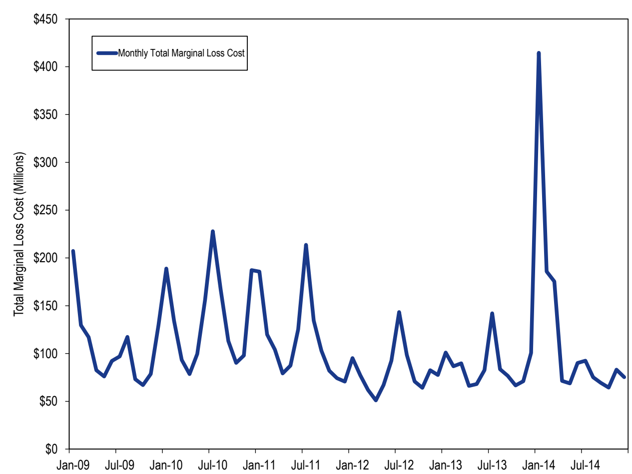
	Marginal Loss Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$105.8	($4.7)	$0.0	$101.1	$431.1	($16.5)	$0.0	$414.6
Feb	$93.2	($6.5)	($0.0)	$86.7	$202.1	($16.3)	$0.0	$185.8
Mar	$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
Oct	$76.1	($9.5)	($0.0)	$66.7	$64.5	($0.1)	$0.0	$64.3
Nov	$79.3	($8.3)	($0.0)	$71.0	$82.9	$0.4	($0.0)	$83.3
Dec	$110.7	($10.0)	($0.0)	$100.7	$76.2	($0.8)	($0.0)	$75.4
Total	$1,137.8	($102.5)	($0.0)	$1,035.3	$1,571.4	($105.3)	$0.0	$1,466.1

Monthly Marginal Loss Costs

Table 11-36 shows a monthly summary of marginal loss costs by market type for 2013 and 2014. Total marginal loss costs increased because of the distribution of high load and outages related to the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013.

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

Figure 11-4 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through 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 11-37 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 2014. The total marginal loss credits increased $143.6 million in 2014 from 2013.

Table 11-37 Marginal loss credits (Dollars (Millions)): 2009 through 2014[31]

	Loss Credit Accounting (Millions)			
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,634.8	($0.6)	$836.4
2011	($793.8)	$1,379.5	$0.9	$586.7
2012	($593.0)	$981.7	($2.0)	$386.7
2013	($687.6)	$1,035.3	($2.9)	$344.8
2014	($977.7)	$1,466.1	($0.0)	$488.4

31 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.

Total Energy Costs

The total energy cost for 2014 was -$977.7 million, which was comprised of load energy payments of $60,258.5 million, generation energy credits of $61,232.0 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$4.2 million. The monthly energy costs for the 2014 ranged from -$272.7 million in January to -$39.1 million in October.

Table 11-38 shows total energy component costs and total PJM billing, for 2009 through 2014. The total energy component costs are net energy costs.

Table 11-38 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2014[32]

	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	($688)	15.9%	$33,862	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)

32 The energy costs include net inadvertent charges.

Energy costs for 2009 through 2014 are shown in Table 11-39 and Table 11-40. Table 11-39 shows PJM energy costs by accounting category for 2009 through 2014 and Table 11-40 shows PJM energy costs by market category for 2009 through 2014. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-38.

Table 11-39 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2014

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	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	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)

Monthly Energy Costs

Table 11-41 shows a monthly summary of energy costs by market type for 2013 and 2014. Marginal total energy costs in 2014 decreased from 2013. Monthly total energy costs in 2014 ranged from -$272.7 million in January to -$39.1 million in October.

Figure 11-5 shows PJM monthly energy costs for January 2009 through December 2014.

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

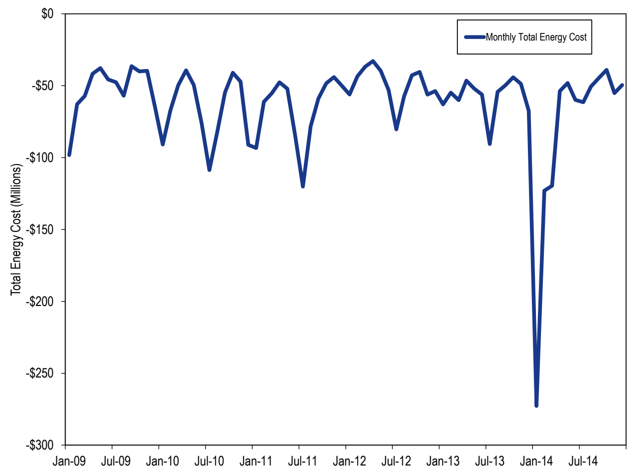


Table 11-40 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2014

	Energy Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	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	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)

Table 11-41 Monthly energy costs by market type (Dollars (Millions)): 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)
Oct	($63.9)	$20.5	($0.8)	($44.2)	($47.5)	$8.3	$0.1	($39.1)
Nov	($71.7)	$24.1	($1.1)	($48.7)	($63.4)	$8.6	($0.4)	($55.2)
Dec	($96.9)	$30.7	($1.3)	($67.5)	($58.3)	$9.0	($0.3)	($49.6)
Total	($833.7)	$153.5	($7.4)	($687.6)	($1,343.7)	$370.2	($4.2)	($977.7)