Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum 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 varies with 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. 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.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $326.1 million or 31.9 percent, from $1,023.7 million in 2016 to $697.6 million in 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $367.4 million or 33.4 percent, from $1,100.4 million in 2016 to $733.1 million in 2017.
- **Balancing Congestion.** Balancing congestion costs increased by $41.3 million or 53.8 percent, from -$76.8 million in 2016 to -$35.5 million in 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $236.1 million or 22.4 percent, from $1,053.7 million in 2016 to $817.5 million in 2017.

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 2013 through 2014.

2 See the 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, 2018, and are subject to change, based on continued PJM billing updates.

- **Monthly Congestion.** Monthly total congestion costs in 2017 ranged from $30.1 million in August to $121.7 million in December.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Braidwood - East Frankfort Line, the Conastone - Peach Bottom Line, the Emilie – Falls Line, the Graceton - Safe Harbor Line and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 9.3 percent from 275,298 congestion event hours in 2016 to 300,923 congestion event hours in 2017.

  Real-time congestion frequency decreased by 15.1 percent from 26,370 congestion event hours in 2016 to 22,400 congestion event hours in 2017.
- **Congested Facilities.** Day-ahead, congestion-event hours increased on flowgates and transformers and decreased on interfaces and lines. Real-time, congestion-event hours increased on interfaces and decreased on lines, flowgates and transformers.

  The Braidwood - East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2017. ComEd had $215.8 million in total congestion costs, comprised of -$237.5 million in total load congestion payments, -$460.2 million in total generation congestion credits and -$6.8 million in explicit congestion costs. The Braidwood – East Frankfort Line, the Cherry Valley Transformer, the Alpine – Belvidere Flowgate, the Brokaw - Leroy Flowgate and the Bryron – Cherry Valley Flowgate contributed $89.6 million, or 41.5 percent of the total ComEd control zone congestion costs.
- **Ownership.** In 2017, financial entities were net receivers and physical entities were net payers of congestion charges. In 2017, financial entities were paid $19.9 million in congestion credits compared to $10.8 million received in congestion credits in 2016. In 2017, physical entities paid $717.5 million in congestion charges, a decrease of $316.9 million or 30.6 percent compared to 2016.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $5.7 million or 0.8 percent, from $696.5 million in 2016 to $690.8 million in 2017. The loss MWh in PJM decreased by 233.8 GWh or 1.5 percent, from 15,153.9 GWh in 2016 to 14,920.1 GWh in 2017. The loss component of real-time LMP in 2017 was $0.0145, compared to $0.0144 in 2016.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2017 ranged from $44.2 million in April to $91.5 million in December.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $3.3 million or 0.4 percent, from $773.2 million in 2016 to $769.9 million in 2017.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $2.4 million or 3.1 percent, from -$76.7 million in 2016 to -$79.1 million in 2017.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2017 by $12.6 million or 5.5 percent, from $227.2 million in 2016, to $214.6 million in 2017.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $8.9 million or 1.9 percent, from -$466.3 million in 2016 to -$475.2 million in 2017.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $7.9 million or 1.2 percent, from -$640.6 million in 2016 to -$648.5 million in 2017.
- **Balancing Energy Costs.** Balancing energy costs decreased by $17.8 million or 9.7 percent, from $184.0 million in 2016 to $166.2 million in 2017.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2017 ranged from -$61.9 million in December to -$31.0 million in April.

Conclusion

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of 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.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. For the first seven months of the 2017/2018 planning period ARRs and self scheduled FTRs offset 79.4 percent of total 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 is 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 the sum 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. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for January 1 through December 31, 2008 through 2017.[7]

The load-weighted average real-time LMP increased $1.76 or 6.0 percent from $29.23 in 2016 to $30.99 in 2017. The load-weighted average congestion component decreased by $0.02 from $0.04 in 2016 to $0.02 in 2017. The load-weighted average loss component in 2017 was $0.0145 compared to $0.0144 in 2016. The load-

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.

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.

weighted average energy component increased by $1.77 or 6.1 percent from $29.18 in 2016 to $30.96 in 2017.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2008 through 2017[8]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
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
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2008 through 2017.[9] The load-weighted average day-ahead LMP increased $1.17, or 3.9 percent, from $29.68 in 2016 to $30.85 in 2017. The load-weighted average congestion component decreased $0.09, or 65.1 percent, from $0.14 in 2016 to $0.05 in 2017. The load-weighted average loss component decreased from -$0.0132 in 2016 to -$0.0167 in 2017. The load-weighted average energy component increased $1.26, or 4.3 percent, from $29.55 in 2016 to $30.81 in 2017.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2008 through 2017

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
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)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)

Table 11-3 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours. In 2017, December had the highest real-time, load-weighted average LMP in the constrained hours which was $44.60.

Table 11-3 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2016 and 2017

	2016		2017	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$31.18	$20.73	$32.96	$26.37
Feb	$26.99	$17.67	$25.82	$24.26
Mar	$23.02	$10.71	$32.56	$26.54
Apr	$29.40	$21.24	$29.26	$23.90
May	$25.13	$19.98	$32.27	$23.90
Jun	$30.03	$16.32	$29.23	$18.80
Jul	$32.82	$23.20	$34.22	$26.33
Aug	$36.25	$22.88	$28.39	$24.66
Sep	$31.37	$15.98	$33.79	$21.28
Oct	$28.15	$20.48	$28.69	$29.20
Nov	$25.73	$25.23	$29.43	$23.26
Dec	$32.81	$28.17	$44.60	$24.74
Avg	$29.75	$21.55	$31.81	$24.42

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for 2016 and 2017. In 2017, BGE had the highest real-time congestion component of all control zones and AECO had the lowest real-time congestion component.

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.

Table 11-4 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

	2016				2017			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$26.93	$29.54	($3.12)	$0.51	$29.63	$31.03	($1.86)	$0.46
AEP	$29.14	$28.98	$0.39	($0.24)	$30.17	$30.78	($0.31)	($0.31)
APS	$29.75	$29.06	$0.69	$0.00	$31.32	$30.92	$0.34	$0.06
ATSI	$29.78	$29.01	$0.13	$0.64	$31.23	$30.70	$0.01	$0.52
BGE	$38.62	$29.41	$8.16	$1.05	$34.76	$31.28	$2.43	$1.06
ComEd	$27.66	$29.11	($0.51)	($0.94)	$28.29	$30.82	($1.35)	($1.19)
DAY	$29.36	$29.16	($0.25)	$0.45	$31.06	$30.87	($0.27)	$0.46
DEOK	$28.62	$29.17	$0.16	($0.72)	$30.55	$30.91	$0.40	($0.77)
DLCO	$29.20	$29.15	$0.29	($0.24)	$30.63	$30.82	($0.04)	($0.15)
Dominion	$32.15	$29.38	$2.62	$0.15	$33.49	$31.21	$1.90	$0.38
DPL	$29.66	$29.50	($0.67)	$0.83	$33.39	$31.35	$1.15	$0.89
EKPC	$28.21	$29.30	($0.31)	($0.78)	$29.19	$31.34	($1.32)	($0.82)
JCPL	$26.36	$29.66	($3.59)	$0.29	$30.74	$31.30	($0.94)	$0.38
Met-Ed	$26.04	$29.16	($3.29)	$0.17	$31.15	$30.97	($0.07)	$0.25
PECO	$25.57	$29.25	($3.79)	$0.11	$29.80	$31.04	($1.38)	$0.14
PENELEC	$27.57	$28.80	($1.57)	$0.34	$30.48	$30.60	($0.33)	$0.22
Pepco	$34.12	$29.42	$4.11	$0.59	$33.70	$31.19	$1.82	$0.69
PPL	$25.43	$29.04	($3.60)	($0.01)	$29.99	$30.96	($0.99)	$0.02
PSEG	$26.24	$29.23	($3.24)	$0.25	$30.92	$30.91	($0.37)	$0.38
RECO	$27.05	$29.76	($3.01)	$0.30	$31.26	$31.28	($0.43)	$0.41
PJM	$29.23	$29.18	$0.04	$0.01	$30.99	$30.96	$0.02	$0.01

The day-ahead components of LMP for each control zone are presented in Table 11-5 for 2016 and 2017. In 2017, BGE had the highest day-ahead congestion component of all control zones and AECO had the lowest day-ahead congestion component.

Table 11-5 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

	2016				2017			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$27.48	$30.02	($3.02)	$0.48	$29.14	$30.94	($1.98)	$0.18
AEP	$29.46	$29.41	$0.30	($0.24)	$30.56	$30.75	$0.05	($0.24)
APS	$30.18	$29.40	$0.87	($0.09)	$31.17	$30.75	$0.42	($0.00)
ATSI	$29.77	$29.41	($0.04)	$0.40	$31.23	$30.62	$0.22	$0.39
BGE	$39.59	$29.98	$8.68	$0.93	$34.78	$31.14	$2.72	$0.92
ComEd	$28.00	$29.50	($0.72)	($0.79)	$28.24	$30.67	($1.59)	($0.84)
DAY	$29.67	$29.46	($0.18)	$0.39	$31.37	$30.82	$0.01	$0.54
DEOK	$29.30	$29.61	$0.31	($0.62)	$31.00	$30.86	$0.66	($0.52)
DLCO	$29.12	$29.57	($0.06)	($0.39)	$30.76	$30.74	$0.23	($0.21)
Dominion	$33.02	$29.84	$3.01	$0.17	$33.59	$31.14	$2.04	$0.42
DPL	$31.00	$30.03	$0.27	$0.70	$32.18	$31.22	$0.45	$0.52
EKPC	$28.62	$29.79	($0.37)	($0.81)	$29.95	$31.32	($0.63)	($0.73)
JCPL	$26.52	$30.01	($3.81)	$0.32	$29.92	$31.06	($1.29)	$0.15
Met-Ed	$26.22	$29.41	($3.23)	$0.04	$30.44	$30.80	($0.34)	($0.03)
PECO	$25.90	$29.60	($3.77)	$0.07	$28.97	$30.76	($1.71)	($0.08)
PENELEC	$27.86	$29.08	($1.42)	$0.21	$29.98	$30.61	($0.65)	$0.02
Pepco	$34.95	$29.65	$4.77	$0.53	$33.71	$30.95	$2.11	$0.64
PPL	$25.68	$29.36	($3.57)	($0.11)	$29.30	$30.74	($1.17)	($0.26)
PSEG	$26.83	$29.75	($3.30)	$0.38	$30.47	$30.86	($0.62)	$0.23
RECO	$27.28	$30.03	($3.16)	$0.41	$30.66	$31.07	($0.66)	$0.25
PJM	$29.68	$29.55	$0.14	($0.01)	$30.85	$30.81	$0.05	($0.02)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for 2016 and 2017.

Table 11-6 Hub real-time, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

	2016				2017			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.97	$29.67	($0.47)	($1.23)	$28.98	$30.94	($0.71)	($1.25)
AEP-DAY Hub	$29.08	$29.41	$0.01	($0.34)	$30.02	$30.95	($0.45)	($0.47)
ATSI Gen Hub	$28.99	$28.81	($0.00)	$0.18	$30.31	$30.63	($0.28)	($0.04)
Chicago Gen Hub	$25.97	$28.65	($1.35)	($1.33)	$27.17	$30.55	($1.79)	($1.59)
Chicago Hub	$28.13	$29.45	($0.44)	($0.89)	$28.83	$31.27	($1.31)	($1.13)
Dominion Hub	$31.68	$29.61	$2.21	($0.13)	$33.70	$31.81	$1.75	$0.15
Eastern Hub	$28.74	$28.68	($0.72)	$0.78	$32.02	$30.42	$0.78	$0.83
N Illinois Hub	$27.21	$28.92	($0.64)	($1.07)	$27.82	$30.69	($1.57)	($1.30)
New Jersey Hub	$26.32	$29.39	($3.35)	$0.28	$30.65	$31.03	($0.75)	$0.37
Ohio Hub	$28.93	$29.08	$0.07	($0.22)	$30.14	$30.91	($0.36)	($0.41)
West Interface Hub	$29.87	$29.18	$0.90	($0.22)	$31.38	$31.13	$0.50	($0.25)
Western Hub	$31.63	$30.58	$1.00	$0.05	$32.45	$32.12	$0.26	$0.07

The day-ahead components of LMP for each hub are presented in Table 11-7 for 2016 and 2017.

Table 11-7 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): 2016 and 2017

	2016				2017			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$28.11	$29.60	($0.32)	($1.17)	$29.53	$30.80	($0.18)	($1.09)
AEP-DAY Hub	$28.89	$29.18	$0.06	($0.35)	$30.14	$30.49	$0.03	($0.38)
ATSI Gen Hub	$26.12	$25.98	$0.10	$0.03	$28.32	$28.13	$0.24	($0.05)
Chicago Gen Hub	$25.71	$28.49	($1.62)	($1.16)	$26.56	$29.95	($2.14)	($1.26)
Chicago Hub	$27.77	$29.17	($0.73)	($0.68)	$27.63	$30.03	($1.66)	($0.74)
Dominion Hub	$32.44	$29.87	$2.64	($0.07)	$33.31	$31.24	$1.84	$0.22
Eastern Hub	$30.84	$29.79	$0.29	$0.76	$32.15	$31.00	$0.59	$0.56
N Illinois Hub	$27.38	$29.04	($0.75)	($0.91)	$27.36	$30.11	($1.77)	($0.97)
New Jersey Hub	$26.65	$29.76	($3.45)	$0.34	$30.15	$30.92	($0.95)	$0.18
Ohio Hub	$28.85	$29.08	$0.04	($0.27)	$30.09	$30.39	$0.03	($0.33)
West Interface Hub	$30.31	$29.68	$0.93	($0.30)	$30.14	$29.53	$0.81	($0.20)
Western Hub	$30.41	$29.17	$1.31	($0.06)	$30.99	$30.81	$0.32	($0.14)

Component Costs

Table 11-8 shows the total energy, loss and congestion component costs and the total PJM billing for 2008 through 2017. These totals are actually net energy, loss and congestion costs. Total congestion cost and marginal loss cost decreased in 2017 compared to 2016.

Table 11-8 Total PJM costs by component (Dollars (Millions)): 2008 through 2017[10 11]

	Component Costs (Millions)					
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2008	($1,193)	$2,497	$2,052	$3,355	$34,306	9.8%
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	$33,860	3.0%
2014	($978)	$1,466	$1,932	$2,421	$50,030	4.8%
2015	($627)	$969	$1,385	$1,727	$42,630	4.1%
2016	($466)	$697	$1,024	$1,254	$39,050	3.2%
2017	($475)	$691	$698	$913	$40,170	2.3%

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.

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 MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **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.[13]

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. Total congestion costs, when positive, measure the total congestion payment

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

13 OA Schedule 1 §3.7.

by a PJM member and when negative, measure the total congestion credit paid to a PJM member. Load congestion payments, when positive, measure the total congestion payment by a PJM member and when negative, measure the total congestion credit paid to a PJM member. Generation congestion credits, when negative, measure the total congestion payment by a PJM member and when positive, measure the total congestion credit paid to a PJM member. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[14]

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.

Total congestion costs in PJM in 2017 were $697.6 million, which was comprised of load congestion payments of $209.7 million, generation credits of -$506.9 million and explicit congestion of -$19.0 million.

Total Congestion

Table 11-9 shows total congestion in 2008 through 2017. Total congestion costs in Table 11-9 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[15 16]

Table 11-9 Total PJM congestion (Dollars (Millions)): 2008 through 2017

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%

Table 11-10 shows total congestion by day-ahead and balancing component for the January through December period, by year. Table 11-10 shows that total negative balancing congestion was lower in 2017 than in 2008 through 2016. The decrease in the level of negative balancing congestion was a result of a large decrease in the level of negative balancing congestion explicit costs. Table 11-11 and Table 11-12 show that the decrease in the level of negative balancing explicit costs was the result of a decrease in the level of negative balancing explicit congestion caused by up to congestion (UTCs) which went from -$47.0 million in 2016 to -$10.8 million in 2017. The decrease in the level of negative balancing explicit congestion cost by up to congestion (UTCs) was the result of PJM's actions to reduce negative balancing by addressing modelling differences between the day-ahead and real-time market models and the lower overall congestion in the system.

14 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

15 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

16 See "NYISO Tariffs New York Independent System Operator, Inc.," (May 26, 2016) Section 35.12.1, Effective Date: October 22, 2014. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2017

	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
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

Table 11-11 and Table 11-12 show the total congestion costs for each transaction type in 2017 and 2016. Table 11-11 shows that in 2017 DECs paid $4.3 million in congestion costs in the day-ahead market, were paid $17.1 million in congestion credits in the balancing energy market, and were paid $12.8 million in total congestion credits. In 2017, INCs were paid $10.3 million in congestion credits in the day-ahead market, paid $0.2 million in congestion charges in the balancing energy market and received $10.2 million in total congestion credits. In 2017, up to congestion (UTCs) were paid $8.9 million in congestion credits in the day-ahead market, were paid $10.8 million in congestion credits in the balancing market and were paid $19.7 million in total congestion credits.

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2017

	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	$4.3	$0.0	$0.0	$4.3	($17.1)	$0.0	$0.0	($17.1)	$0.0	($12.8)
Demand	$35.7	$0.0	$0.0	$35.7	$40.2	$0.0	$0.0	$40.2	$0.0	$75.9
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.0	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0
Export	($29.7)	$0.0	($0.5)	($30.3)	($4.4)	$0.0	$1.8	($2.6)	$0.0	($32.9)
Generation	$0.0	($739.9)	$0.0	$739.9	$0.0	$53.5	$0.0	($53.5)	$0.0	$686.3
Grandfathered Overuse	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.5)
Import	$0.0	($1.7)	$0.0	$1.7	$0.0	($9.5)	($0.9)	$8.7	$0.0	$10.4
INC	$0.0	$10.3	$0.0	($10.3)	$0.0	($0.2)	$0.0	$0.2	$0.0	($10.2)
Internal Bilateral	$177.4	$177.3	($0.1)	($0.0)	$3.6	$3.6	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($8.9)	($8.9)	$0.0	$0.0	($10.8)	($10.8)	$0.0	($19.7)
Wheel In	$0.0	($0.1)	$0.1	$0.2	$0.0	($0.2)	($0.1)	$0.1	$0.0	$0.3
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.4)
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

Table 11-12 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2016

	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	$56.3	$0.0	$0.0	$56.3	($59.6)	$0.0	$0.0	($59.6)	$0.0	($3.3)
Demand	$61.3	$0.0	$0.0	$61.3	$45.5	$0.0	$0.0	$45.5	$0.0	$106.8
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	$0.0	$0.0	$4.9	$4.9	$0.0	$0.0	$0.0	$0.0	$0.0	$4.9
Explicit Congestion Only	($72.6)	$0.0	($0.5)	($73.1)	($9.8)	$0.0	$2.0	($7.9)	$0.0	($81.0)
Generation	$0.0	($1,043.0)	$0.0	$1,043.0	$0.0	$33.9	$0.0	($33.9)	$0.0	$1,009.1
Grandfathered Overuse	$0.0	$0.0	$0.3	$0.3	$0.0	$0.0	$0.2	$0.2	$0.0	$0.5
Import	$0.0	($6.3)	$0.1	$6.4	$0.0	($7.8)	$0.9	$8.8	$0.0	$15.2
INC	$0.0	$33.1	$0.0	($33.1)	$0.0	($17.2)	$0.0	$17.2	$0.0	($15.9)
Internal Bilateral	$382.4	$384.2	$1.8	($0.0)	$19.5	$19.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$32.7	$32.7	$0.0	$0.0	($47.0)	($47.0)	$0.0	($14.3)
Wheel In	$0.0	($22.1)	$1.7	$23.7	$0.0	($0.1)	$0.0	$0.1	$0.0	$23.8
Wheel Out	($22.1)	$0.0	$0.0	($22.1)	($0.1)	$0.0	$0.0	($0.1)	$0.0	($22.1)
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.3	($43.9)	($76.8)	$0.0	$1,023.7

Table 11-13 shows the change in total congestion cost incurred by transaction type from 2016 to 2017. Total congestion cost incurred by generation decreased by $322.8 million, and total congestion cost incurred by demand decreased by $30.9 million.

The total congestion payments to up to congestion transactions (UTCs) increased by $5.4 million, from $14.3 million in 2016 to $19.7 million 2017. Total day-ahead congestion costs paid by UTCs decreased by $41.6 million from $32.7 million in 2016 to -$8.9 million in 2017. In other words, UTCs paid $32.7 million in congestion charges in 2016 and were paid $8.9 million in congestion credits in 2017 in the day-ahead market. Over the same period balancing congestion payments to UTCs decreased by $36.2 million, from $47.0 million in 2016 to $10.8 million in 2017.

Table 11-13 Change in total PJM congestion costs by transaction type by market: 2016 to 2017 (Dollars (Millions))

	Change in 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	($51.9)	$0.0	$0.0	($51.9)	$42.5	$0.0	$0.0	$42.5	$0.0	($9.4)
Demand	($25.7)	$0.0	$0.0	($25.7)	($5.3)	$0.0	$0.0	($5.3)	$0.0	($30.9)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	($3.9)	($3.9)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($3.9)
Export	$42.9	$0.0	($0.1)	$42.8	$5.4	$0.0	($0.2)	$5.2	$0.0	$48.1
Generation	$0.0	$303.1	$0.0	($303.1)	$0.0	$19.6	$0.0	($19.6)	$0.0	($322.8)
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.5)	($0.5)	$0.0	($1.0)
Import	$0.0	$4.5	($0.1)	($4.7)	$0.0	($1.7)	($1.8)	($0.1)	$0.0	($4.7)
INC	$0.0	($22.7)	$0.0	$22.7	$0.0	$17.0	$0.0	($17.0)	$0.0	$5.7
Internal Bilateral	($205.0)	($206.9)	($1.9)	($0.0)	($15.9)	($15.9)	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($41.6)	($41.6)	$0.0	$0.0	$36.2	$36.2	$0.0	($5.4)
Wheel In	$0.0	$21.9	($1.6)	($23.5)	$0.0	($0.2)	($0.2)	($0.0)	$0.0	($23.5)
Wheel Out	$21.9	$0.0	$0.0	$21.9	($0.2)	$0.0	$0.0	($0.2)	$0.0	$21.8
Total	($217.8)	$100.0	($49.6)	($367.4)	$26.7	$18.9	$33.5	$41.3	$0.0	($326.1)

Monthly Congestion

Table 11-14 shows that monthly total congestion costs ranged from $30.1 million in August to $121.7 million in December, 2017. The high congestion cost in December was caused by high day-ahead congestion costs from December 27, 2017 through December 31, 2017. The total day-ahead congestion costs of those five days contributed 58.2 percent ($81.4 million out of $139.8 million) of total day-ahead congestion costs in December. The total day-ahead congestion costs from December 27, 2017 through December 31, 2017 were mainly a result of the 5004/5005 Interface, Carson – Rawlings Line and Cloverdale Transformer constraints. The high day-ahead load, high gas prices, dispatch of high cost units resulted in high shadow prices for those constraints and high negative CLMPs on the low side of those constraints which resulted in high negative day-ahead generation credits on those days. Negative generation credits are positive congestion costs.

Table 11-14 Monthly PJM congestion costs by market (Dollars (Millions)): 2017

	Congestion Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$123.5	($16.0)	$0.0	$107.6	$66.4	($6.5)	($0.0)	$59.9
Feb	$123.8	($12.5)	$0.0	$111.3	$44.4	$2.1	$0.0	$46.5
Mar	$75.6	($2.2)	($0.0)	$73.3	$54.1	($2.5)	$0.0	$51.6
Apr	$81.2	($3.0)	$0.0	$78.2	$30.7	($0.1)	$0.0	$30.5
May	$41.6	$7.5	($0.0)	$49.1	$36.7	($4.0)	$0.0	$32.7
Jun	$68.2	($8.6)	($0.0)	$59.6	$64.5	($0.2)	$0.0	$64.4
Jul	$124.4	($13.6)	($0.0)	$110.8	$51.7	($10.4)	$0.0	$41.3
Aug	$116.0	($5.0)	($0.0)	$111.0	$34.3	($4.2)	$0.0	$30.1
Sep	$123.4	($2.1)	($0.0)	$121.4	$99.7	($1.2)	$0.0	$98.5
Oct	$115.7	($12.6)	($0.0)	$103.1	$50.8	$11.3	$0.0	$62.1
Nov	$48.9	($0.9)	($0.0)	$48.0	$59.9	($1.5)	($0.0)	$58.3
Dec	$58.0	($7.8)	($0.0)	$50.3	$139.8	($18.1)	($0.0)	$121.7
Total	$1,100.4	($76.8)	($0.0)	$1,023.7	$733.1	($35.5)	$0.0	$697.6

Figure 11-1 shows PJM monthly total congestion cost for January 1, 2009 through December 31, 2017.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through 2017

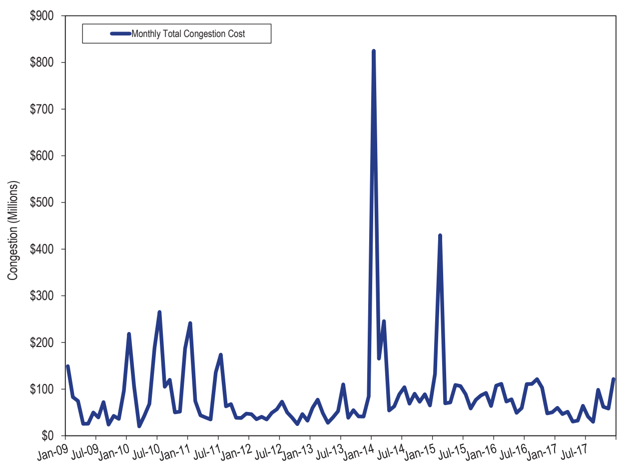


Table 11-15 shows the monthly total congestion costs for each virtual transaction type in 2017 and Table 11-16 shows the monthly total congestion costs for each virtual transaction type in 2016. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-15 and Table 11-16 show that virtuals were paid in 2017 and in 2016.

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Total	DEC	INC	Up to Congestion	Virtual Total	Grand Total
Jan	$1.1	$0.3	$2.9	$4.3	($3.0)	($1.1)	($2.0)	($6.1)	($1.9)
Feb	($0.7)	($4.9)	$0.7	($4.8)	($1.6)	$3.4	$1.7	$3.5	($1.4)
Mar	($1.2)	$2.3	($1.4)	($0.3)	$0.4	($2.6)	$1.2	($1.0)	($1.3)
Apr	($1.5)	$0.2	$0.7	($0.6)	$1.3	($0.6)	$0.6	$1.4	$0.8
May	($3.5)	$1.4	$0.2	($1.8)	$1.7	($3.2)	$0.6	($0.9)	($2.7)
Jun	($0.3)	$1.0	($0.3)	$0.3	$0.2	($1.5)	$1.4	$0.0	$0.4
Jul	$0.6	$1.1	$1.0	$2.7	($2.2)	($3.2)	($5.1)	($10.5)	($7.9)
Aug	$2.0	$0.4	$1.6	$3.9	($2.1)	($1.3)	($2.7)	($6.1)	($2.2)
Sep	$2.3	$0.9	($3.8)	($0.6)	($2.6)	($2.2)	($2.7)	($7.5)	($8.1)
Oct	$1.8	($8.6)	($3.9)	($10.8)	($2.5)	$7.6	$3.8	$8.9	($1.9)
Nov	$2.0	($4.3)	$1.0	($1.3)	($3.1)	$3.0	($2.1)	($2.2)	($3.5)
Dec	$1.9	($0.2)	($7.6)	($5.9)	($3.6)	$1.9	($5.5)	($7.2)	($13.1)
Total	$4.3	($10.3)	($8.9)	($14.9)	($17.1)	$0.2	($10.8)	($27.7)	($42.7)

Table 11-16 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Total	DEC	INC	Up to Congestion	Total	Grand Total
Jan	$6.8	($0.8)	$4.2	$10.1	($6.1)	($1.5)	($11.6)	($19.2)	($9.0)
Feb	$6.0	($1.0)	$1.2	$6.1	($8.1)	($0.5)	($6.3)	($14.9)	($8.8)
Mar	$5.1	($5.3)	$0.8	$0.5	($3.9)	$3.8	($1.2)	($1.3)	($0.8)
Apr	$5.0	($3.9)	($0.9)	$0.2	($5.1)	$4.3	($0.7)	($1.5)	($1.3)
May	$3.4	($8.9)	$0.8	($4.8)	($2.4)	$7.4	$1.8	$6.9	$2.1
Jun	$3.9	$0.0	$7.6	$11.6	($2.6)	($1.5)	($7.2)	($11.4)	$0.2
Jul	$3.5	$0.2	$5.5	$9.2	($6.0)	($1.7)	($7.5)	($15.2)	($5.9)
Aug	$7.4	($3.0)	$4.9	$9.3	($7.4)	$1.2	($5.5)	($11.8)	($2.5)
Sep	$6.8	($3.9)	$4.5	$7.4	($7.9)	$1.6	($1.2)	($7.6)	($0.2)
Oct	$4.9	($3.7)	$0.1	$1.3	($5.0)	$3.1	($4.0)	($5.8)	($4.5)
Nov	$1.7	($1.6)	$1.5	$1.6	($1.8)	$0.9	($1.0)	($1.9)	($0.3)
Dec	$1.7	($1.1)	$2.7	$3.4	($3.3)	$0.1	($2.7)	($5.9)	($2.5)
Total	$56.3	($33.1)	$32.7	$55.9	($59.6)	$17.2	($47.0)	($89.5)	($33.5)

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 2017, there were 300,923 day-ahead, congestion-event hours compared to 275,298 day-ahead congestion-event hours in 2016. Of 2017 day-ahead congestion-event hours, only 11,342 (3.8 percent) were also constrained in the Real-Time Energy Market. In 2017, there were 22,400 real-time, congestion-event hours compared to 26,370 real-time, congestion-event hours in 2016. Of 2017 real-time congestion-event hours, 11,121 (49.6 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints in terms of congestion costs contributed $154.4 million, or 22.1 percent, of the total PJM congestion costs in 2017. The top five constraints were the Braidwood - East Frankfort, the Conastone - Peach Bottom Line, the Emilie – Falls Line, the Graceton - Safe Harbor Line and the 5004/5005 Interface.

The top three constraints by total congestion costs changed from Conastone - Northwest Line, Graceton Transformer, and Bagley – Gracetone Line in the BGE Zone in 2016 to the Braidwood - East Frankfort Line in the ComEd Zone, the Emilie – Falls Line in the Pepco Zone in 2017 and the Conastone - Peach Bottom Line in the PECO Zone. The change in the BGE Zone was primarily a result of the completion of RTEP upgrades and and the end of outages in the BGE Zone related to the RTEP upgrades.

Congestion by Facility Type and Voltage

In 2017, day-ahead, congestion-event hours increased on flowgates and transformers and decreased on lines and interfaces.

The increase in day-ahead, congestion-event hours on flowgates was largely a result of the increase of day-ahead, congestion-event hours on MISO flowgates. The day-ahead, congestion-event hours on flowgates in MISO increased from 23,893 event hours in 2016 to 29,064 event hours in 2017. The increase in day-ahead, congestion-event hours on transformers was primarily a result of the increase in day-ahead, congestion-event hours on transformers in the ComEd, PENELEC and PSEG zones. The decrease in day-ahead, congestion-event hours on interfaces was a result of the decrease in day-ahead, congestion-event hours on AEP - DOM and Bedington - Black Oak. The decrease in day-ahead, congestion-event hours on lines was primarily a result of a decrease in day-ahead, congestion-event hours on lines in AECO, BGE and ComEd zones.

Real-time, congestion-event hours increased on interfaces and decreased on flowgates, lines and transformers. The increase in real-time, congestion-event hours on interfaces was primarily a result of the increase in real-time, congestion-event hours on the 5004/5005 interface. The 5004/5005 interface constraints were caused by the Keystone substation equipment outages in December. The decrease in real-time, congestion-event hours on flowgates was primarily a result of the decrease in real-time, congestion-event hours on flowgates in NYISO. The decrease in real-time, congestion-event hours on lines was primarily a result of a decrease in real-time, congestion-event hours incurred by lines in BGE, ComEd and DPL zones.

Day-ahead congestion costs decreased on all types of facilities except interfaces in 2017 compared to 2016, as indicated by the decrease in day-ahead load-weighted CLMP. The load-weighted average congestion component decreased $0.09, or 65.1 percent, from $0.14 in 2016 to $0.05 in 2017.

Balancing congestion costs increased on flowgates and lines and decreased on interfaces and transformers in 2017 compared to 2016. Table 11-17 provides congestion-event hour subtotals and congestion cost subtotals comparing 2017 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17] [18]

Table 11-18 presents this information for 2016.

Table 11-17 Congestion summary (By facility type): 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($52.9)	($207.3)	($24.6)	$129.8	$7.0	$6.4	($2.7)	($2.2)	$127.6	29,579	5,975
Interface	$16.0	($58.8)	($7.0)	$67.8	$4.9	$14.2	$5.7	($3.6)	$64.2	4,635	439
Line	$186.3	($233.0)	$12.6	$431.9	$5.8	$20.3	($0.0)	($14.5)	$417.4	155,443	12,963
Other	$4.9	($6.2)	$1.0	$12.1	$0.7	$1.3	$0.9	$0.3	$12.4	16,623	529
Transformer	$33.2	($48.7)	$9.4	$91.3	$3.8	$3.8	($13.6)	($13.6)	$77.6	94,643	2,494
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.0	$1.2	($0.7)	($1.8)	($1.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,400

Table 11-18 Congestion summary (By facility type): 2016

	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

17 Unclassified are congestion costs related to nontransmission facility constraints in the Day-Ahead Energy Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

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

Flowgate	($30.8)	($261.2)	($16.5)	$213.9	($0.1)	$17.5	($15.6)	($33.3)	$180.7	23,964	6,039
Interface	$29.5	($20.5)	($2.5)	$47.6	$0.3	$0.3	$0.2	$0.2	$47.8	4,959	155
Line	$313.1	($256.5)	$44.7	$614.3	($1.6)	$9.7	($28.0)	($39.3)	$575.0	161,398	16,610
Other	$2.2	($1.8)	$0.6	$4.6	$0.3	($0.1)	($0.9)	($0.4)	$4.2	13,520	203
Transformer	$91.3	($113.9)	$14.5	$219.7	($2.1)	$3.0	($3.4)	($8.5)	$211.2	71,457	3,363
Unclassified	($0.1)	($0.2)	$0.1	$0.3	($1.3)	($2.0)	$3.8	$4.5	$4.8	NA	NA
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$1,023.7	275,298	26,370

Table 11-19 and Table 11-20 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 11-19. In 2017, there were 300,923 congestion-event hours in the Day-Ahead Energy Market. Of those day-ahead congestion-event hours, only 11,342 (3.8 percent) were also constrained in the Real-Time Energy Market. In 2016, of the 275,298 day-ahead congestion-event hours, only 14,435 (5.2 percent) were binding in the Real-Time Energy Market.[19]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-20. In 2017, of the 22,400 congestion-event hours in the Real-Time Energy Market, 11,121 (49.6 percent) were also constrained in the Day-Ahead Energy Market. In 2016, of the 26,370 real-time congestion-event hours, 14,339 (54.4 percent) were also in the Day-Ahead Energy Market.

Table 11-19 Congestion event hours (day-ahead against real-time): 2016 and 2017

	Congestion Event Hours					
	2016			2017		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	23,964	2,682	11.2%	29,579	2,464	8.3%
Interface	4,959	75	1.5%	4,635	268	5.8%
Line	161,398	9,425	5.8%	155,443	7,726	5.0%
Other	13,520	9	0.1%	16,623	28	0.2%
Transformer	71,457	2,244	3.1%	94,643	856	0.9%
Total	275,298	14,435	5.2%	300,923	11,342	3.8%

Table 11-20 Congestion event hours (real-time against day-ahead): 2016 and 2017

	Congestion Event Hours					
	2016			2017		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	6,039	2,657	44.0%	5,975	2,473	41.4%
Interface	155	85	54.8%	439	331	75.4%
Line	16,610	9,343	56.2%	12,963	7,475	57.7%
Other	203	9	4.4%	529	28	5.3%
Transformer	3,363	2,245	66.8%	2,494	814	32.6%
Total	26,370	14,339	54.4%	22,400	11,121	49.6%

Table 11-21 shows congestion costs by facility voltage class for 2017. Congestion costs in 2017 decreased for all facilities except 500 kV, 115 kV and 13kV compared to 2016 (Table 11-22).

Table 11-21 Congestion summary (By facility voltage): 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.2)	$0.8	$2.6	($0.2)	$0.0	$0.0	($0.2)	$2.4	1,070	35

19 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.

500	$74.5	($70.2)	($5.7)	$139.0	$7.9	$17.2	$8.8	($0.4)	$138.6	9,061	1,533
345	($11.0)	($140.4)	$1.0	$130.4	$8.3	$9.3	($16.8)	($17.8)	$112.6	59,380	3,220
230	$121.0	($47.5)	$1.6	$170.1	$7.3	$18.7	($1.6)	($13.0)	$157.1	47,474	5,750
161	($0.0)	($0.3)	($0.0)	$0.3	($0.1)	$0.1	($0.1)	($0.2)	$0.0	33	34
138	($10.6)	($266.5)	($4.1)	$251.8	$4.2	$13.5	($4.2)	($13.6)	$238.2	128,573	8,795
115	$3.7	($34.5)	$0.1	$38.2	($0.8)	$2.2	$1.3	($1.7)	$36.6	30,626	1,913
69	$9.1	$7.2	($2.7)	($0.9)	($4.5)	($15.1)	$2.7	$13.2	$12.4	17,329	1,120
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
34	$0.3	$0.0	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	5,573	0
18	($0.0)	($0.6)	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,677	0
17	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	101	0
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.0	$1.2	($0.7)	($1.8)	($1.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,400

Table 11-22 Congestion summary (By facility voltage): 2016

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($2.0)	$1.4	$4.1	$0.0	($0.0)	($0.0)	($0.0)	$4.1	1,527	5
500	$55.3	($42.1)	($1.2)	$96.2	$4.5	$4.3	$3.6	$3.8	$100.0	8,373	1,085
345	($13.0)	($170.8)	$21.5	$179.3	$1.1	$19.2	($25.7)	($43.9)	$135.4	49,044	4,720
230	$297.9	($102.0)	($2.1)	$397.8	$10.3	($0.4)	$3.6	$14.3	$412.1	43,862	7,939
161	($20.2)	($60.5)	($10.4)	$29.8	($2.6)	$4.4	$1.7	($5.2)	$24.6	5,262	1,427
138	$34.3	($275.4)	$26.2	$335.8	($5.7)	$18.6	($26.2)	($50.5)	$285.3	117,296	7,139
115	$21.5	($16.0)	$3.0	$40.5	($2.5)	$0.7	($3.9)	($7.1)	$33.4	22,359	1,202
69	$28.6	$15.0	$2.3	$15.8	($8.4)	($16.5)	($0.9)	$7.2	$23.0	22,822	2,794
34.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	48	0
34	$0.6	$0.0	$0.2	$0.8	($0.0)	$0.0	$0.1	$0.1	$0.8	4,607	59
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	59	0
12	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	39	0
Unclassified	($0.1)	($0.2)	$0.1	$0.3	($1.3)	($2.0)	$3.8	$4.5	$4.8	NA	NA
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$1,023.7	275,298	26,370

Constraint Duration

Table 11-23 lists the constraints in 2016 and 2017 that were most frequently binding and Table 11-24 shows the constraints which experienced the largest change in congestion-event hours from 2016 to 2017.

Table 11-23 Top 25 constraints with frequent occurrence: 2016 and 2017[20]

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2016	2017	Change	2016	2017	Change	2016	2017	Change	2016	2017	Change
1	Quad Cities	Transformer	1,046	9,457	8,411	0	0	0	12%	108%	96%	0%	0%	0%
2	Olive	Other	6,092	6,460	368	0	0	0	70%	74%	4%	0%	0%	0%
3	Emilie - Falls	Line	2,617	5,171	2,554	329	895	566	30%	59%	29%	4%	10%	6%
4	Zion	Line	2,929	4,644	1,715	0	0	0	33%	53%	19%	0%	0%	0%
5	Waukegan	Transformer	2,326	4,579	2,253	0	0	0	27%	52%	26%	0%	0%	0%
6	Braidwood - East Frankfort	Line	2,130	4,171	2,041	337	301	(36)	24%	47%	23%	4%	3%	(0%)
7	East Bend	Transformer	2,700	4,464	1,764	0	0	0	31%	51%	20%	0%	0%	0%
8	Hinchmans	Transformer	222	4,378	4,156	0	0	0	3%	50%	47%	0%	0%	0%
9	Graceton - Safe Harbor	Line	590	3,118	2,528	131	1,151	1,020	7%	35%	29%	1%	13%	12%
10	Loretto - Vienna	Line	1,867	3,950	2,083	6	60	54	21%	45%	24%	0%	1%	1%
11	Conastone - Peach Bottom	Line	2,407	3,159	752	699	840	141	27%	36%	8%	8%	10%	2%
12	Westwood	Flowgate	950	3,399	2,449	137	198	61	11%	39%	28%	2%	2%	1%
13	West Chicago	Transformer	2,222	3,490	1,268	0	0	0	25%	40%	14%	0%	0%	0%
14	Cherry Valley	Transformer	5,319	3,007	(2,312)	774	149	(625)	61%	34%	(26%)	9%	2%	(7%)
15	Saddlebrook	Transformer	1,810	3,098	1,288	0	0	0	21%	35%	15%	0%	0%	0%
16	Howard - Shelby	Line	4,169	3,041	(1,128)	0	0	0	48%	35%	(13%)	0%	0%	0%
17	Electric Junction	Transformer	0	2,906	2,906	0	0	0	0%	33%	33%	0%	0%	0%
18	Gould Street - Westport	Line	2,782	2,800	18	27	0	(27)	32%	32%	0%	0%	0%	(0%)
19	Essex Co. RRF	Transformer	1,202	2,793	1,591	0	0	0	14%	32%	18%	0%	0%	0%
20	Tanners Creek	Transformer	2,548	2,679	131	0	0	0	29%	30%	1%	0%	0%	0%
21	West Moulton - City Of St. Marys	Line	3,718	2,677	(1,041)	0	0	0	42%	30%	(12%)	0%	0%	0%
22	Hudson	Transformer	2,795	2,610	(185)	0	0	0	32%	30%	(2%)	0%	0%	0%
23	Liquid Carbonics	Transformer	1,340	2,586	1,246	0	0	0	15%	29%	14%	0%	0%	0%
24	Elwood	Other	3,849	2,571	(1,278)	0	0	0	44%	29%	(15%)	0%	0%	0%
25	Maywood	Transformer	3,422	2,540	(882)	0	0	0	39%	29%	(10%)	0%	0%	0%

20 The constraints are presented in descending order of total of day-ahead event hours and real-time event hours in 2017.

Table 11-24 Top 25 constraints with largest year-to-year change in occurrence: 2016 and 2017[21]

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2016	2017	Change	2016	2017	Change	2016	2017	Change	2016	2017	Change
1	Quad Cities	Transformer	1,046	9,457	8,411	0	0	0	12%	108%	96%	0%	0%	0%
2	Monroe - Vineland	Line	5,354	343	(5,011)	439	13	(426)	61%	4%	(57%)	5%	0%	(5%)
3	Mercer IP - Galesburg	Flowgate	3,510	0	(3,510)	1,155	0	(1,155)	40%	0%	(40%)	13%	0%	(13%)
4	Graceton	Transformer	3,117	0	(3,117)	1,298	0	(1,298)	36%	0%	(36%)	15%	0%	(15%)
5	Bagley - Graceton	Line	3,313	554	(2,759)	1,685	127	(1,558)	38%	6%	(32%)	19%	1%	(18%)
6	Hinchmans	Transformer	222	4,378	4,156	0	0	0	3%	50%	47%	0%	0%	0%
7	Graceton - Safe Harbor	Line	590	3,118	2,528	131	1,151	1,020	7%	35%	29%	1%	13%	12%
8	East Danville - Banister	Line	3,643	237	(3,406)	20	2	(18)	42%	3%	(39%)	0%	0%	(0%)
9	Conastone - Northwest	Line	2,776	975	(1,801)	1,840	228	(1,612)	32%	11%	(21%)	21%	3%	(18%)
10	Emilie - Falls	Line	2,617	5,171	2,554	329	895	566	30%	59%	29%	4%	10%	6%
11	Cherry Valley	Transformer	5,319	3,007	(2,312)	774	149	(625)	61%	34%	(26%)	9%	2%	(7%)
12	Electric Junction	Transformer	0	2,906	2,906	0	0	0	0%	33%	33%	0%	0%	0%
13	Westwood	Flowgate	950	3,399	2,449	137	198	61	11%	39%	28%	2%	2%	1%
14	Reynolds - Magnetation	Flowgate	2,062	297	(1,765)	680	31	(649)	24%	3%	(20%)	8%	0%	(7%)
15	Seneca	Transformer	146	2,495	2,349	0	0	0	2%	28%	27%	0%	0%	0%
16	Beryl - Westvaco	Line	0	2,306	2,306	0	0	0	0%	26%	26%	0%	0%	0%
17	Waukegan	Transformer	2,326	4,579	2,253	0	0	0	27%	52%	26%	0%	0%	0%
18	Mardela - Vienna	Line	2,367	577	(1,790)	380	5	(375)	27%	7%	(20%)	4%	0%	(4%)
19	Tidd	Transformer	2,422	276	(2,146)	0	0	0	28%	3%	(25%)	0%	0%	0%
20	Havana E - Havana S	Flowgate	118	2,260	2,142	0	0	0	1%	26%	24%	0%	0%	0%
21	Loretto - Vienna	Line	1,867	3,950	2,083	6	60	54	21%	45%	24%	0%	1%	1%
22	Kincaid - Pana North	Line	2,127	0	(2,127)	0	0	0	24%	0%	(24%)	0%	0%	0%
23	Halifax - Roanoke Rapids	Line	0	2,069	2,069	0	0	0	0%	24%	24%	0%	0%	0%
24	Braidwood	Transformer	4,138	2,086	(2,052)	0	0	0	47%	24%	(23%)	0%	0%	0%
25	Braidwood - East Frankfort	Line	2,130	4,171	2,041	337	301	(36)	24%	47%	23%	4%	3%	(0%)

21 The constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2016 to 2017.

Constraint Costs

Table 11-25 and Table 11-26 show the top constraints affecting congestion costs by facility for 2017 and 2016. The Braidwood – East Frankfort Line was the largest contributor to congestion costs in 2017. With $43.4 million in total congestion costs, it accounted for 6.2 percent of the total PJM congestion costs in 2017.

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2017

				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	2017
1	Braidwood - East Frankfort	Line	ComEd	($4.7)	($49.7)	$0.3	$45.3	$0.7	$1.9	($0.7)	($1.9)	$43.4	6.2%
2	Conastone - Peach Bottom	Line	500	$38.7	$1.6	$0.1	$37.2	$2.0	$1.3	$1.5	$2.2	$39.5	5.7%
3	Emilie - Falls	Line	PECO	$12.0	($13.6)	($0.1)	$25.6	($0.1)	$1.2	$0.8	($0.4)	$25.1	3.6%
4	Graceton - Safe Harbor	Line	BGE	$30.2	$7.1	($0.0)	$23.1	$1.7	$2.3	$1.4	$0.8	$23.9	3.4%
5	5004/5005 Interface	Interface	500	($9.9)	($38.7)	($3.8)	$25.0	$4.3	$11.4	$4.6	($2.5)	$22.5	3.2%
6	AP South	Interface	500	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	3.1%
7	Westwood	Flowgate	MISO	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	2.8%
8	Cherry Valley	Transformer	ComEd	$8.9	($10.1)	$2.1	$21.0	($0.6)	$0.9	($0.9)	($2.3)	$18.7	2.7%
9	Carson - Rawlings	Line	Dominion	$14.5	($4.3)	$0.8	$19.6	$1.0	$1.6	($0.8)	($1.4)	$18.2	2.6%
10	Conastone - Otter Creek	Line	PPL	$23.0	$8.5	($0.5)	$13.9	$1.5	$1.8	$1.5	$1.2	$15.1	2.2%
11	Conastone - Northwest	Line	BGE	$12.7	($1.1)	($0.4)	$13.4	$0.4	$0.7	$1.0	$0.7	$14.1	2.0%
12	Three Mile Island	Transformer	500	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.6)	$0.9	$1.4	$13.3	1.9%
13	Butler - Shanorma	Line	APS	($10.5)	($20.9)	$1.0	$11.4	$0.0	$0.0	$0.0	$0.0	$11.4	1.6%
14	Lakeview - Greenfield	Line	ATSI	($3.5)	($14.5)	$0.2	$11.2	$0.1	$0.7	$0.3	($0.4)	$10.8	1.5%
15	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	1.5%
16	Bedington - Black Oak	Interface	500	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1.4%
17	Person - Sedge Hill	Line	Dominion	$16.2	$3.5	$2.0	$14.7	$0.6	$2.7	($3.2)	($5.3)	$9.3	1.3%
18	Lake George - Aetna	Flowgate	MISO	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.8	$2.7	$9.2	1.3%
19	Batesville - Hubble	Flowgate	MISO	($5.5)	($19.4)	($4.5)	$9.4	($0.2)	($1.2)	($1.6)	($0.6)	$8.9	1.3%
20	Byron - Cherry Valley	Flowgate	MISO	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	1.1%
21	AEP - DOM	Interface	500	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.5	$0.2	$0.3	$7.8	1.1%
22	Brunner Island - Yorkanna	Line	Met-Ed	$6.0	($1.6)	($0.3)	$7.3	($0.0)	($0.1)	$0.1	$0.2	$7.5	1.1%
23	Brokaw - Leroy	Flowgate	MISO	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1.0%
24	Loretto - Vienna	Line	DPL	$8.8	$2.3	$0.7	$7.2	($0.4)	$0.1	$0.2	($0.3)	$6.9	1.0%
25	Pleasant View - Ashburn	Line	Dominion	$5.8	($3.7)	($0.3)	$9.1	($1.1)	$1.0	($0.1)	($2.3)	$6.8	1.0%

Table 11-26 Top 25 constraints affecting PJM congestion costs (By facility): 2016

				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	2016
1	Conastone - Northwest	Line	BGE	$114.8	$7.4	($4.6)	$102.8	$3.9	($2.4)	$6.5	$12.7	$115.5	11.3%
2	Graceton	Transformer	BGE	$53.1	($21.0)	($0.9)	$73.3	($0.9)	($4.7)	$1.8	$5.6	$78.9	7.7%
3	Bagley - Graceton	Line	BGE	$72.5	$5.8	($1.9)	$64.8	$2.7	($2.7)	$2.2	$7.7	$72.5	7.1%
4	Cherry Valley	Transformer	ComEd	$20.4	($27.9)	$3.9	$52.3	($3.0)	$2.6	($5.7)	($11.3)	$40.9	4.0%
5	Cherry Valley	Flowgate	MISO	($5.7)	($44.0)	($0.5)	$37.8	$0.0	$0.0	$0.0	$0.0	$37.8	3.7%
6	Conastone - Peach Bottom	Line	500	$27.9	($0.2)	$0.8	$28.9	$1.3	$0.9	$0.0	$0.4	$29.3	2.9%
7	Braidwood - East Frankfort	Line	ComEd	($3.8)	($38.2)	$0.8	$35.2	$0.5	$3.3	($3.5)	($6.3)	$28.9	2.8%
8	Mercer IP - Galesburg	Flowgate	MISO	($17.1)	($49.9)	($8.9)	$23.9	($0.2)	$3.6	$2.2	($1.6)	$22.3	2.2%
9	Byron - Cherry Valley	Flowgate	MISO	($5.5)	($22.6)	$0.9	$18.0	$0.0	$0.0	$0.0	$0.0	$18.0	1.8%
10	Milford - Steele	Line	DPL	($8.6)	($26.7)	$0.1	$18.1	$2.2	$1.4	($1.7)	($0.9)	$17.2	1.7%
11	AP South	Interface	500	$13.8	($4.9)	($1.9)	$16.8	$0.1	$0.1	$0.0	$0.0	$16.8	1.6%
12	Dixon - McGirr Rd	Flowgate	MISO	($5.0)	($22.9)	($1.2)	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1.6%
13	Reynolds - Magnetation	Flowgate	MISO	($5.1)	($23.9)	$0.9	$19.8	$0.5	$1.5	($2.6)	($3.5)	$16.2	1.6%
14	Bedington - Black Oak	Interface	500	$9.5	($6.2)	($0.6)	$15.2	$0.2	$0.2	$0.1	$0.1	$15.3	1.5%
15	Coolspring - Milford	Line	DPL	$1.3	($11.8)	($0.0)	$13.1	($1.0)	($1.8)	$0.3	$1.1	$14.1	1.4%
16	Loudoun	Transformer	Dominion	$1.1	($9.8)	($0.2)	$10.6	$1.5	$2.2	$3.4	$2.7	$13.3	1.3%
17	Person - Halifax	Flowgate	MISO	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	1.3%
18	Kanawha River - Matt Funk	Line	AEP	$2.7	($17.1)	($1.1)	$18.8	($0.7)	$2.5	($3.3)	($6.6)	$12.2	1.2%
19	Plymouth Meeting - Whitpain	Line	PECO	($0.6)	($10.9)	($0.1)	$10.2	($0.1)	$0.1	$0.2	($0.0)	$10.1	1.0%
20	AEP - DOM	Interface	500	$3.5	($4.5)	$0.2	$8.2	$0.3	($0.0)	$0.1	$0.3	$8.5	0.8%
21	Braidwood - East Frankfurt	Flowgate	MISO	($0.1)	($7.7)	$0.7	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	0.8%
22	Cherry Valley - Silver Lake	Flowgate	MISO	($1.8)	($9.4)	$0.8	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	0.8%
23	Brambleton - Loudoun	Line	Dominion	($2.9)	($10.2)	$0.2	$7.5	$0.2	($0.1)	$0.4	$0.6	$8.1	0.8%
24	Kanawha	Transformer	AEP	$0.1	($7.1)	$0.7	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	0.8%
25	Stockton - Kenney	Line	DPL	($2.5)	$3.4	($1.9)	($7.8)	$0.0	$0.0	$0.0	$0.0	($7.8)	(0.8%)

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in 2017. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted average CLMP in 2017. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in 2017.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2017

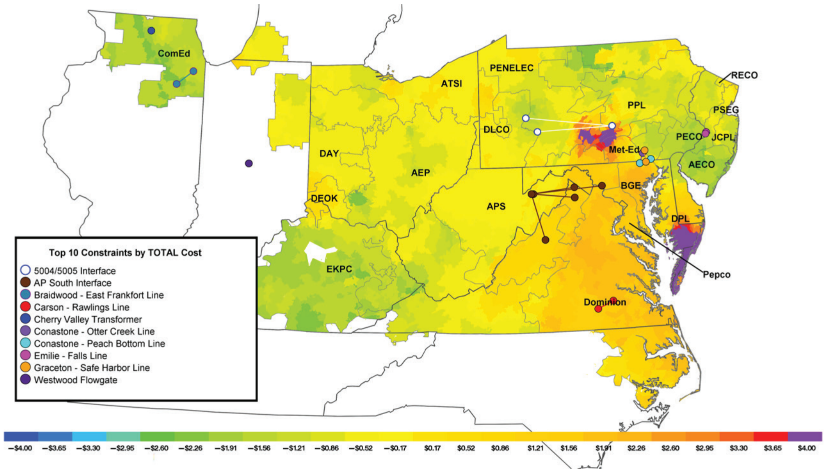


Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: 2017

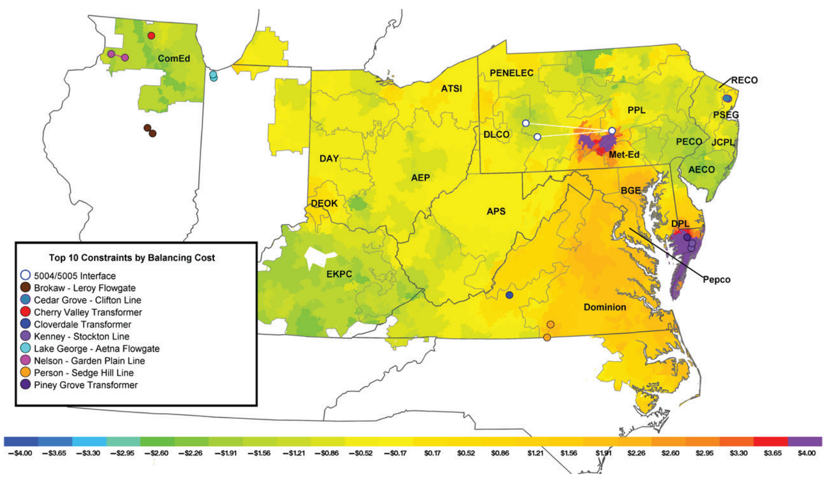
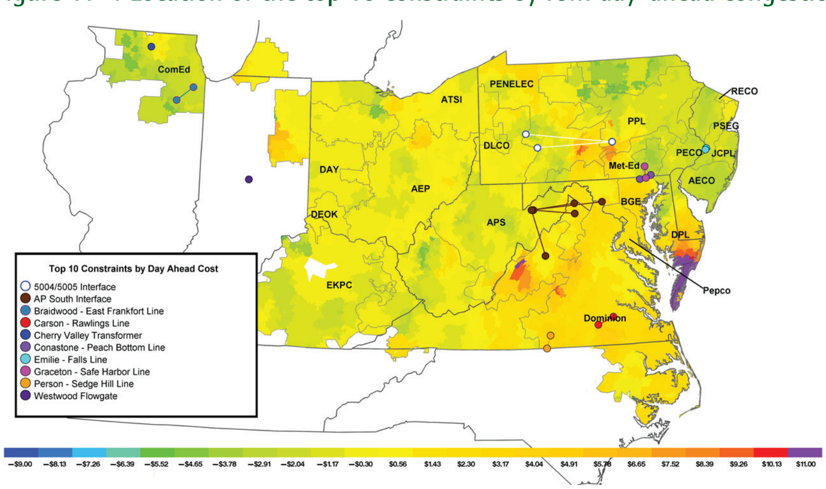


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: 2017



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

As of December 31, 2017, PJM had 140 flowgates eligible for M2M (Market to Market) coordination and MISO had 234 flowgates eligible for M2M coordination.

Table 11-27 and Table 11-28 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2017 and 2016, 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 2017, the Westwood Flowgate made the most significant contribution to positive congestion while the Roxana - Praxair Flowgate made the most significant contribution to negative congestion.

Table 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2017

		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	Westwood	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	3,399	198
2	Alpine - Belvidere	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	339	0
3	Lake George - Aetna	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.8	$2.7	$9.2	483	244
4	Batesville - Hubble	($5.5)	($19.4)	($4.5)	$9.4	($0.2)	($1.2)	($1.6)	($0.6)	$8.9	379	158
5	Byron - Cherry Valley	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	347	0
6	Brokaw - Leroy	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1,744	528
7	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.8)	($0.2)	$1.1	$0.5	$6.1	425	248
8	Havana E - Havana S	($2.6)	($8.3)	($0.2)	$5.5	$0.0	$0.0	$0.0	$0.0	$5.5	2,260	0
9	Dresden	($0.3)	($4.8)	($0.2)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1,216	0
10	Nelson	($2.2)	($6.6)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	534	0
11	Shadelnd - Lafaysouth	($4.4)	($7.7)	$0.1	$3.5	$6.7	$4.7	($2.3)	($0.3)	$3.2	1,055	669
12	Nucor - Whitestown	($0.8)	($5.1)	($1.1)	$3.2	$0.1	$0.1	($0.1)	($0.1)	$3.1	519	19
13	Roxana - Praxair	($0.1)	$0.4	($0.5)	($1.0)	$1.3	$0.0	($3.4)	($2.1)	($3.0)	1,734	290
14	Todd Hunter	($0.6)	($3.6)	($0.0)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	988	0
15	Burnham - Munster	$0.2	($2.3)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	760	0
16	Quad Cities	($1.3)	($3.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	460	0
17	Pleasant Prairie - Zion	($0.6)	($3.3)	($0.1)	$2.7	$0.0	$0.1	($0.2)	($0.2)	$2.4	2,052	395
18	Olive - Bosserman	$1.2	($1.5)	($0.4)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	133	0
19	Havana South - Mason City West	($0.6)	($2.1)	$0.1	$1.6	$0.2	($0.3)	($0.0)	$0.4	$2.0	753	181
20	Reynolds - Magnetation	($0.3)	($1.9)	$0.4	$2.0	$0.0	($0.1)	($0.1)	($0.0)	$2.0	297	31

22 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

23 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24, Effective Date: February 14, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-28 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2016

		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	Cherry Valley	($5.7)	($44.0)	($0.5)	$37.8	$0.0	$0.0	$0.0	$0.0	$37.8	1,329	0
2	Mercer IP - Galesburg	($17.1)	($49.9)	($8.9)	$23.9	($0.2)	$3.6	$2.2	($1.6)	$22.3	3,510	1,155
3	Byron - Cherry Valley	($5.5)	($22.6)	$0.9	$18.0	$0.0	$0.0	$0.0	$0.0	$18.0	298	0
4	Dixon - McGirr Rd	($5.0)	($22.9)	($1.2)	$16.7	$0.0	$0.0	$0.0	$0.0	$16.7	1,779	0
5	Reynolds - Magnetation	($5.1)	($23.9)	$0.9	$19.8	$0.5	$1.5	($2.6)	($3.5)	$16.2	2,062	680
6	Person - Halifax	$29.9	$16.1	($0.2)	$13.5	$0.0	$0.0	($0.2)	($0.2)	$13.3	719	5
7	Braidwood - East Frankfurt	($0.1)	($7.7)	$0.7	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	616	0
8	Cherry Valley - Silver Lake	($1.8)	($9.4)	$0.8	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	484	0
9	Dumont	($1.4)	($10.3)	($1.3)	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	472	0
10	Alpine - Belvidere	($1.9)	($9.5)	($0.1)	$7.5	$0.0	$0.0	$0.0	$0.0	$7.5	496	0
11	Batesville - Hubble	($3.2)	($11.3)	($1.0)	$7.1	$0.5	($0.5)	($2.3)	($1.2)	$5.8	419	134
12	Westwood	($1.6)	($6.5)	($0.8)	$4.2	$0.4	$0.0	$0.3	$0.7	$4.9	950	137
13	Cayuga	($0.6)	($2.4)	($0.1)	$1.7	($0.6)	$3.9	($1.6)	($6.1)	($4.4)	147	74
14	Oak Grove - Galesburg	($3.3)	($8.3)	($1.1)	$3.9	$0.1	$0.2	$0.2	$0.1	$4.0	1,336	174
15	Michigan City - Bosserman	($0.6)	($5.1)	($1.7)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	623	0
16	Pleasant Prairie - Zion	($0.7)	($3.2)	$0.0	$2.5	$0.1	$0.2	($0.2)	($0.3)	$2.2	1,249	409
17	West Dekalb - Glidden	($0.4)	($2.5)	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	318	0
18	Greentown	($0.1)	($1.2)	($0.1)	$1.1	$0.6	$3.6	($0.1)	($3.1)	($2.0)	164	26
19	Roxana - Praxair	($0.7)	($3.3)	($1.6)	$1.0	$0.7	($0.1)	($3.6)	($2.9)	($1.9)	884	143
20	Reynold - Monticello	($0.5)	($3.3)	$0.7	$3.5	$0.4	$1.1	($0.9)	($1.6)	$1.9	561	0

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.[24] 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.[25]

Table 11-29 and Table 11-30 show the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2017 and 2016, and which had the greatest congestion cost impact on PJM.

Table 11-29 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2017

				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	($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332

Table 11-30 Top three congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2016

				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	($0.1)	($0.4)	$0.0	$0.3	$0.6	$1.7	($0.2)	($1.3)	($1.0)	64	1,074
2	West Central Ties	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	6
3	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2

24 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.3.1, Effective Date: January 15, 2013. <http://www.pjm.com/documents/agreements.aspx>.
25 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.23, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-31 and Table 11-32 show the 500 kV constraints affecting congestion costs in PJM for 2017 and 2016. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-31 Regional constraints summary (By facility): 2017

				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	Conastone - Peach Bottom	Line	500	$38.7	$1.6	$0.1	$37.2	$2.0	$1.3	$1.5	$2.2	$39.5	3,159	840
2	5004/5005 Interface	Interface	500	($9.9)	($38.7)	($3.8)	$25.0	$4.3	$11.4	$4.6	($2.5)	$22.5	173	104
3	AP South	Interface	500	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	1,315	74
4	Three Mile Island	Transformer	500	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.6)	$0.9	$1.4	$13.3	540	86
5	Bedington - Black Oak	Interface	500	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1,215	61
6	AEP - DOM	Interface	500	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.5	$0.2	$0.3	$7.8	948	33
7	West	Interface	500	($0.4)	($2.1)	($0.2)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	180	0
8	Limerick	Transformer	500	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	67	0
9	Conastone	Transformer	500	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	33	2
10	Cabot - Keystone	Line	500	($0.1)	($0.5)	$0.1	$0.5	$0.1	$0.2	($0.0)	($0.2)	$0.3	97	18
11	East	Interface	500	($0.5)	($1.1)	($0.1)	$0.6	$0.2	$0.7	$0.2	($0.3)	$0.3	131	10
12	Belmont	Transformer	500	($0.0)	($0.2)	($0.1)	$0.1	$0.0	$0.1	($0.3)	($0.4)	($0.3)	42	52
13	Keeney - Rockspring	Line	500	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	39	0
14	502 Junction	Transformer	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	42	0
15	Bristers - Ox	Line	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
16	Redlion	Transformer	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	55	0
17	Central	Interface	500	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
18	Elroy - Hosensack	Line	500	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
19	Cabot	Other	500	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
20	Hope Creek - Red Lion	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0

Table 11-32 Regional constraints summary (By facility): 2016

				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	Conastone - Peach Bottom	Line	500	$27.9	($0.2)	$0.8	$28.9	$1.3	$0.9	$0.0	$0.4	$29.3	2,407	699
2	AP South	Interface	500	$13.8	($4.9)	($1.9)	$16.8	$0.1	$0.1	$0.0	$0.0	$16.8	1,076	14
3	Bedington - Black Oak	Interface	500	$9.5	($6.2)	($0.6)	$15.2	$0.2	$0.2	$0.1	$0.1	$15.3	1,515	105
4	AEP - DOM	Interface	500	$3.5	($4.5)	$0.2	$8.2	$0.3	($0.0)	$0.1	$0.3	$8.5	1,604	5
5	502 Junction	Transformer	500	$0.3	($3.3)	$0.1	$3.7	$0.0	$0.1	($0.0)	($0.1)	$3.6	321	2
6	Three Mile Island	Transformer	500	$1.2	($1.5)	$0.3	$3.0	$0.1	($0.0)	$0.1	$0.2	$3.2	298	47
7	Brambleton - Mosby	Line	500	($0.5)	($3.5)	$0.1	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	151	0
8	West	Interface	500	($0.9)	($3.1)	($0.1)	$2.1	$0.2	($0.1)	($0.0)	$0.3	$2.4	165	2
9	Belmont	Transformer	500	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.9)	($1.1)	($1.1)	0	6
10	East	Interface	500	($0.7)	($1.6)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	112	0
11	5004/5005 Interface	Interface	500	($0.2)	($1.1)	($0.1)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	42	0
12	Yukon	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.2	$0.1	$0.6	$0.7	$0.7	0	16
13	Bristers - Ox	Line	500	$0.0	($0.0)	$0.0	$0.1	$0.4	$0.2	$0.2	$0.4	$0.5	25	6
14	Keeney - Rockspring	Line	500	($0.3)	($0.7)	$0.1	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	81	0
15	Redlion	Transformer	500	($0.0)	($0.2)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	68	0
16	Carson	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.2	$0.2	($0.3)	($0.3)	($0.3)	7	4
17	Cabot - Keystone	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.2	$0.2	($0.2)	($0.1)	($0.1)	2	10
18	Keeney - Rockspri	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1	$0.1	$0.1	0	11
19	Wylie Ridge	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	0	6
20	Conastone	Transformer	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0

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.

Financial entities received $10.8 million (Table 11-34) in net congestion credits in 2016 and $19.9 million in net congestion credits in 2017. Physical entities paid $1,034.4 million in congestion charges in 2016 and $717.5 million in congestion charges in 2017.

Explicit congestion costs are the primary source of congestion credits to financial entities, primarily UTCs. Total explicit congestion cost is equal to day-ahead explicit congestion cost plus balancing explicit congestion cost. In 2016, the total day-ahead explicit congestion cost was $41.0, of which $32.7 million (79.8 percent) was credited to UTCs. For the same period, the total balancing explicit congestion cost was -$43.9 million, of which -$47.0 million (107.1 percent) was credited to UTCs. In 2017, the total explicit congestion cost was -$10.0 million, of which -$19.7 million (104.0 percent) was contributed by UTCs.

Congestion-Event Summary: Impact of Changes in UTC Volumes

FERC issued a notice, effective September 8, 2014, that UTCs could be liable on a retroactive basis for paying uplift charges.[26] That potential refund period ended, after 15 months, on December 7, 2015.[27]

In 2016, the average hourly UTC submitted MW increased 70.3 percent and UTC cleared MW increased 78.6 percent, compared to 2015.[28] Day-ahead congestion event hours increased by 48.9 percent from 184,851 congestion event hours in 2015 to 275,298 congestion event hours in 2016.

In 2017, the average hourly UTC submitted MW decreased 3.3 percent and UTC cleared MW increased 1.6 percent, compared to 2016. Day-ahead congestion event hours increased by 9.3 percent from 275,298 congestion event hours in 2016 to 300,923 congestion event hours in 2017.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through December 31, 2017.

Table 11-33 Congestion cost by type of participant: 2017

	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	$17.6	$14.5	($18.3)	($15.2)	($11.6)	($7.8)	($0.9)	($4.7)	$0.0	($19.9)
Physical	$169.9	($568.6)	$9.8	$748.3	$33.8	$55.0	($9.5)	($30.8)	$0.0	$717.5
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

Table 11-34 Congestion cost by type of participant: 2016

	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	$24.2	($1.7)	$10.2	$36.1	($34.4)	($11.8)	($24.3)	($46.9)	$0.0	($10.8)
Physical	$381.2	($652.4)	$30.8	$1,064.3	$29.9	$40.2	($19.6)	($29.9)	$0.0	$1,034.4
Total	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	$0.0	$1,023.7

26 See 18 CFR § 385.213 (2014).
27 See 148 FERC ¶ 61,144 (2014); 16 U.S.C. § 824e.
28 See 2016 State of the Market Report for PJM, Volume 2 Section 3: Energy Market, Table 3-35.

Figure 11-5 Daily congestion event hours: 2014 through 2017

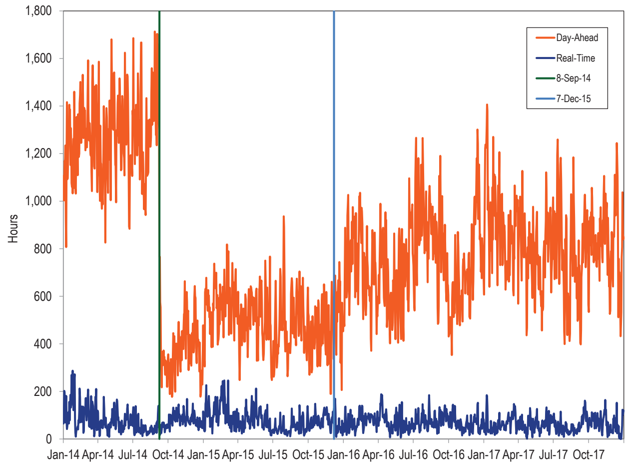
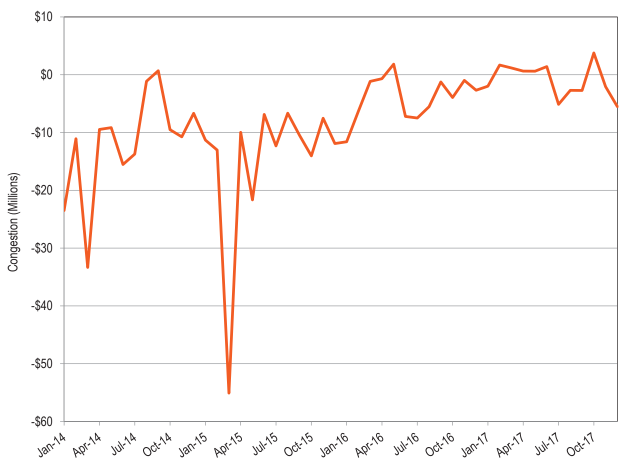


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from 2014 through 2017. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March of 2015 and the highest monthly charge ($3.8 million) in balancing congestion charges occurred in October of 2017.

Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: 2014 through 2017



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. 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 be more accurately thought of as net marginal loss costs. Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[29] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[30] 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. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Load loss payments, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Generation loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

29 OA Schedule 1 §3.7
30 *Id.*

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.

The total 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 allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[31]

- **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 MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **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, including UTCs. 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 MW 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

31 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 77 (Nov. 1, 2017) at 70.

in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[32]

Total Marginal Loss Cost

The total marginal loss cost in PJM for 2017 was $690.8 million, which was comprised of load loss payments of -$40.9 million, generation loss credits of -$766.9 million, explicit loss costs of -$35.1 million and inadvertent loss charges of $0.0 million (Table 11-36).

Monthly marginal loss costs in 2017 ranged from $44.2 million in April to $91.5 million in December. Total marginal loss surplus decreased in 2017 by $12.6 million or 5.5 percent from $227.2 million in 2016 to $214.6 million in 2017.

Table 11-35 shows the total marginal loss costs as a component of total energy related costs for January 1 through December 31, 2008 through 2017.

Table 11-35 Total component costs (Dollars (Millions)): 2008 through 2017[33]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,306	7.3%
2009	$1,268	(49.2%)	$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%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%

Table 11-36 shows PJM total marginal loss costs by accounting category for January 1 through December 31, 2008 through 2017. Table 11-37 shows PJM total marginal loss costs by accounting category by market for January 1 through December 31, 2008 through 2017.

Table 11-36 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2017

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
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
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8

32 OA Schedule 1 §3.7.

33 The loss costs include net inadvertent charges.

Table 11-37 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2017

	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
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
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
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8

Table 11-38 and Table 11-39 show the total loss costs for each transaction type in 2017 and 2016. In 2017, generation paid loss costs of $731.9 million, 105.9 percent of total loss costs. In 2016, generation paid loss costs of $727.1 million, 104.4 percent of total loss costs.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In 2017, DECs were paid $7.7 million in loss credits in the day-ahead market, paid $6.0 million in congestion costs in the balancing energy market and received $1.7 million in net payment for losses. In 2017, INCs paid $13.8 million in loss costs in the day-ahead market, were paid $12.0 million in congestion credits in the balancing energy market and paid $1.8 million in net payment for losses. In 2017, up to congestion paid $54.9 million in loss costs in the day-ahead market, were paid $90.0 million in loss credits in the balancing energy market and received $35.1 million in net payment for losses.

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)):2017

	Loss 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	($7.7)	$0.0	$0.0	($7.7)	$6.0	$0.0	$0.0	$6.0	$0.0	($1.7)
Demand	($5.6)	$0.0	$0.0	($5.6)	$11.4	$0.0	$0.0	$11.4	$0.0	$5.8
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($17.3)	$0.0	$0.1	($17.2)	($7.8)	$0.0	$0.8	($7.0)	$0.0	($24.2)
Generation	$0.0	($730.0)	$0.0	$730.0	$0.0	($1.9)	$0.0	$1.9	$0.0	$731.9
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.9)
Import	$0.0	($1.9)	$0.0	$1.9	$0.0	($11.5)	($0.3)	$11.2	$0.0	$13.1
INC	$0.0	($13.8)	$0.0	$13.8	$0.0	$12.0	$0.0	($12.0)	$0.0	$1.8
Internal Bilateral	($21.6)	($21.5)	$0.1	($0.0)	$1.7	$1.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$54.9	$54.9	$0.0	$0.0	($90.0)	($90.0)	$0.0	($35.1)
Wheel In	$0.0	($0.0)	$0.4	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.4
Wheel Out	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Total	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8

Table 11-39 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2016

	Loss 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	($5.2)	$0.0	$0.0	($5.2)	$2.2	$0.0	$0.0	$2.2	$0.0	($3.0)
Demand	($5.6)	$0.0	$0.0	($5.6)	$9.3	$0.0	$0.0	$9.3	$0.0	$3.7
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($18.9)	$0.0	$0.3	($18.6)	($6.2)	$0.0	$0.7	($5.5)	$0.0	($24.1)
Generation	$0.0	($732.6)	$0.0	$732.6	$0.0	$5.4	$0.0	($5.4)	$0.0	$727.1
Grandfathered Overuse	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($1.1)
Import	$0.0	($5.3)	$0.7	$6.1	$0.0	($18.5)	$0.5	$19.0	$0.0	$25.0
INC	$0.0	($11.9)	$0.0	$11.9	$0.0	$11.1	$0.0	($11.1)	$0.0	$0.7
Internal Bilateral	($32.1)	($31.8)	$0.3	($0.0)	$1.4	$1.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$51.6	$51.6	$0.0	$0.0	($84.8)	($84.8)	$0.0	($33.1)
Wheel In	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	($0.0)	($0.0)	$0.0	$1.2
Total	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	$0.0	$696.5

Monthly Marginal Loss Costs

Table 11-40 shows a monthly summary of marginal loss costs by market type for January 1, 2016 through December 31, 2017.

Table 11-40 Monthly marginal loss costs by market (Millions): 2016 and 2017

	Marginal Loss Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$78.2	($6.2)	$0.0	$72.0	$75.5	($13.2)	($0.0)	$62.3
Feb	$61.3	($3.8)	$0.0	$57.5	$54.2	($7.8)	$0.0	$46.4
Mar	$43.8	($3.2)	($0.0)	$40.6	$70.2	($7.4)	$0.0	$62.8
Apr	$52.1	($6.0)	$0.0	$46.1	$50.8	($6.6)	$0.0	$44.2
May	$40.4	($3.9)	($0.0)	$36.6	$55.0	($4.9)	$0.0	$50.1
Jun	$59.6	($6.5)	($0.0)	$53.1	$59.0	($4.2)	$0.0	$54.8
Jul	$93.8	($7.5)	($0.0)	$86.4	$78.7	($7.1)	$0.0	$71.6
Aug	$95.6	($9.8)	($0.0)	$85.8	$64.4	($7.6)	$0.0	$56.8
Sep	$70.6	($6.6)	($0.0)	$64.0	$58.3	($6.2)	$0.0	$52.0
Oct	$51.6	($6.6)	($0.0)	$45.0	$51.8	($4.7)	$0.0	$47.1
Nov	$49.0	($6.9)	($0.0)	$42.1	$55.3	($4.0)	$0.0	$51.3
Dec	$77.2	($9.7)	($0.0)	$67.5	$96.8	($5.3)	$0.0	$91.5
Total	$773.2	($76.7)	($0.0)	$696.5	$769.9	($79.1)	$0.0	$690.8

Figure 11-7 shows PJM monthly marginal loss costs for January 1, 2008 through December 31, 2017.

Figure 11-7 PJM monthly marginal loss costs (Dollars (Millions)): 2017

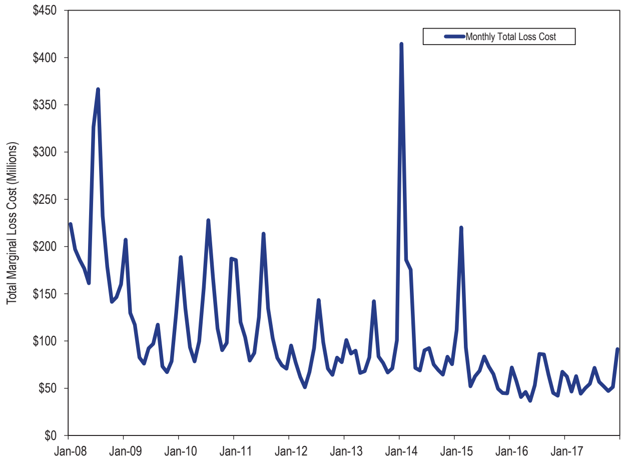


Table 11-41 and Table 11-42 show the monthly total loss costs for each virtual transaction type in 2017 and 2016.

Table 11-41 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Total	DEC	INC	Up to Congestion	Total	Grand Total
Jan	($0.6)	$1.5	$6.7	$7.6	($0.0)	($1.3)	($13.4)	($14.7)	($7.1)
Feb	($0.6)	$1.3	$5.3	$6.0	$0.4	($1.1)	($7.7)	($8.4)	($2.4)
Mar	($1.1)	$2.6	$5.3	$6.7	$0.7	($2.0)	($8.1)	($9.3)	($2.6)
Apr	($1.1)	$0.8	$4.5	$4.2	$1.0	($0.9)	($6.8)	($6.6)	($2.4)
May	($1.3)	$1.6	$4.3	$4.6	$1.1	($1.3)	($6.4)	($6.7)	($2.1)
Jun	($0.8)	$1.1	$3.8	$4.1	$0.8	($0.9)	($5.8)	($5.9)	($1.7)
Jul	($1.0)	$1.4	$5.1	$5.5	$0.9	($0.9)	($8.0)	($8.1)	($2.7)
Aug	($0.3)	$0.6	$5.0	$5.3	$0.3	($0.6)	($7.8)	($8.1)	($2.8)
Sep	($0.4)	$1.0	$2.9	$3.5	$0.5	($1.1)	($7.4)	($8.0)	($4.5)
Oct	($0.2)	$0.8	$3.6	$4.2	$0.4	($0.9)	($5.9)	($6.4)	($2.2)
Nov	($0.3)	$0.7	$3.7	$4.2	$0.2	($0.7)	($5.4)	($5.8)	($1.6)
Dec	($0.1)	$0.4	$4.6	$4.9	($0.2)	($0.3)	($7.4)	($7.9)	($3.0)
Total	($7.7)	$13.8	$54.9	$61.0	$6.0	($12.0)	($90.0)	($96.1)	($35.1)

Table 11-42 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Loss Costs (Millions)								
	Day-Ahead				Balancing				
	DEC	INC	Up to Congestion	Total	DEC	INC	Up to Congestion	Total	Grand Total
Jan	$0.3	$1.2	$3.7	$5.1	($0.6)	($1.1)	($6.8)	($8.5)	($3.3)
Feb	$0.1	$0.8	$1.9	$2.8	($0.0)	($0.8)	($4.3)	($5.2)	($2.4)
Mar	($0.0)	$1.1	$1.3	$2.4	($0.1)	($1.0)	($3.4)	($4.5)	($2.0)
Apr	($0.1)	$1.0	$3.9	$4.8	($0.1)	($0.8)	($6.3)	($7.3)	($2.5)
May	($0.3)	$0.7	$2.1	$2.4	$0.0	($0.5)	($4.7)	($5.2)	($2.8)
Jun	($0.7)	$1.0	$4.8	$5.1	$0.7	($1.0)	($7.6)	($7.9)	($2.8)
Jul	($1.0)	$1.4	$5.8	$6.2	$0.7	($1.2)	($8.5)	($9.0)	($2.7)
Aug	($0.5)	$1.0	$7.7	$8.2	$0.4	($1.3)	($11.6)	($12.5)	($4.3)
Sep	($0.7)	$0.8	$5.0	$5.1	$0.5	($1.1)	($7.0)	($7.6)	($2.5)
Oct	($0.8)	$0.9	$4.6	$4.7	$0.5	($0.7)	($6.3)	($6.5)	($1.8)
Nov	($0.3)	$0.8	$4.6	$5.1	($0.3)	($0.7)	($6.9)	($7.9)	($2.8)
Dec	($1.1)	$1.1	$6.3	$6.3	$0.5	($0.9)	($11.3)	($11.7)	($5.3)
Total	($5.2)	$11.9	$51.6	$58.3	$2.2	($11.1)	($84.8)	($93.7)	($35.4)

Marginal Loss Costs and Loss Credits

Total 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 the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-43 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2008 through 2017. The total marginal loss surplus decreased $12.6 million in 2017 from 2016.

Table 11-43 Marginal loss credits (Dollars (Millions)): 2008 through 2017[34]

	Loss Credit Accounting (Millions)					
			Net Residual Market Adjustment			
	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Loss Surplus
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	$0.0	($0.7)	($0.0)	$639.7
2010	($797.9)	$1,634.8	$0.1	$0.7	($0.0)	$836.4
2011	($793.8)	$1,379.5	$0.1	($1.0)	$0.1	$586.7
2012	($593.0)	$981.7	$0.0	$2.0	($0.0)	$386.7
2013	($687.6)	$1,035.3	$0.1	$3.0	($0.0)	$344.8
2014	($977.7)	$1,466.1	($0.0)	$6.3	$0.1	$482.1
2015	($627.4)	$968.7	($0.0)	$5.1	($0.1)	$336.3
2016	($466.3)	$696.5	($0.0)	$3.2	($0.2)	$227.2
2017	($475.2)	$690.8	$0.0	$1.1	($0.1)	$214.6

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 or total loss 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 be more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for 2017 was -$475.2 million, which was comprised of load energy payments of $35,152.1 million, generation energy credits of $35,643.4 million, explicit energy costs of $0.0 million and inadvertent energy charges of $7.1 million. The monthly energy costs for 2017 ranged from -$61.9 million in December to -$31.0 million in April.

Table 11-44 shows total energy component costs and total PJM billing, for January 1 through December 31, 2008 through 2017. The total energy component costs are net energy costs.

Table 11-44 Total PJM costs by energy component (Dollars (Millions)): 2008 through 2017[35]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,306	(3.5%)
2009	($629)	(47.3%)	$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%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)

Energy costs for January 1 through December 31, 2008 through 2017 are shown in Table 11-45 and Table 11-46. Table 11-45 shows PJM energy costs by accounting category for January 1 through December 31, 2008 through 2017 and Table 11-46 shows PJM energy costs by market category for January 1 through December 31, 2008 through 2017.

34 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.

35 The energy costs include net inadvertent charges.

Table 11-45 Total PJM energy costs by accounting category (Dollars (Millions)): 2008 through 2017

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
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)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)

Table 11-46 Total PJM energy costs by market category (Dollars (Millions)): 2008 through 2017

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
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)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)

Table 11-47 and Table 11-48 show the total energy costs for each transaction type in 2017 and 2016. In 2017, generation was paid $24,566.8 million and demand paid $23,484.2 million in net energy payment. In 2016, generation was paid $23,752.0 million and demand paid $23,099.8 million in net energy payment.

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2017

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,092.8	$0.0	$0.0	$1,092.8	($1,095.6)	$0.0	$0.0	($1,095.6)	($2.9)
Demand	$23,433.7	$0.0	$0.0	$23,433.7	$50.5	$0.0	$0.0	$50.5	$23,484.2
Demand Response	($0.6)	$0.0	$0.0	($0.6)	$0.6	$0.0	$0.0	$0.6	($0.0)
Export	$707.1	$0.0	$0.0	$707.1	$346.6	$0.0	$0.0	$346.6	$1,053.6
Generation	$0.0	$24,616.7	$0.0	($24,616.7)	$0.0	($50.0)	$0.0	$50.0	($24,566.8)
Import	$0.0	$81.1	$0.0	($81.1)	$0.0	$361.2	$0.0	($361.2)	($442.2)
INC	$0.0	$1,183.6	$0.0	($1,183.6)	$0.0	($1,175.3)	$0.0	$1,175.3	($8.2)
Internal Bilateral	$10,257.2	$10,257.2	$0.0	($0.0)	$359.9	$359.9	$0.0	$0.0	($0.0)
Wheel In	$0.0	$0.3	$0.0	($0.3)	$0.0	$0.8	$0.0	($0.8)	($1.2)
Wheel Out	$0.3	$0.0	$0.0	$0.3	$0.8	$0.0	$0.0	$0.8	$1.2
Total	$35,490.4	$36,139.0	$0.0	($648.5)	($337.2)	($503.4)	$0.0	$166.2	($482.3)

Table 11-48 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2016

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,254.0	$0.0	$0.0	$1,254.0	($1,239.3)	$0.0	$0.0	($1,239.3)	$14.7
Demand	$22,886.5	$0.0	$0.0	$22,886.5	$213.3	$0.0	$0.0	$213.3	$23,099.8
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	($0.1)
Export	$653.2	$0.0	$0.0	$653.2	$308.0	$0.0	$0.0	$308.0	$961.2
Generation	$0.0	$23,956.2	$0.0	($23,956.2)	$0.0	($204.2)	$0.0	$204.2	($23,752.0)
Import	$0.0	$201.8	$0.0	($201.8)	$0.0	$553.5	$0.0	($553.5)	($755.3)
INC	$0.0	$1,275.2	$0.0	($1,275.2)	$0.0	($1,250.4)	$0.0	$1,250.4	($24.8)
Internal Bilateral	$9,452.4	$9,452.4	$0.0	$0.0	$525.5	$525.5	$0.0	$0.0	$0.0
Total	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($456.6)

Monthly Energy Costs

Table 11-49 shows a monthly summary of energy costs by market type for 2017. Marginal total energy costs in 2017 decreased from 2016. Monthly total energy costs in 2017 ranged from -$61.9 million in December to -$31.0 million in April.

Table 11-49 Monthly energy costs by market type (Dollars (Millions)): 2016 and 2017

	Energy Costs (Millions)							
	2016				2017			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($63.8)	$15.4	$0.6	($47.7)	($75.6)	$28.9	($1.5)	($48.2)
Feb	($50.0)	$11.1	$0.4	($38.5)	($48.3)	$16.5	$0.0	($31.8)
Mar	($36.6)	$9.3	($0.1)	($27.4)	($59.9)	$17.5	$0.2	($42.2)
Apr	($43.6)	$12.7	$0.3	($30.6)	($46.7)	$15.2	$0.5	($31.0)
May	($37.4)	$11.5	($0.3)	($26.1)	($46.2)	$12.6	$1.0	($32.6)
Jun	($50.9)	$17.6	($0.6)	($33.8)	($45.8)	$8.6	$0.7	($36.4)
Jul	($74.3)	$17.5	($0.9)	($57.8)	($61.3)	$14.7	$1.2	($45.4)
Aug	($72.9)	$18.2	($1.2)	($55.9)	($52.7)	$12.8	$1.1	($38.9)
Sep	($54.0)	$14.8	($1.2)	($40.5)	($47.9)	$9.0	$1.3	($37.5)
Oct	($42.7)	$16.4	($3.5)	($29.9)	($43.7)	$8.2	$1.7	($33.8)
Nov	($43.9)	$16.7	($1.5)	($28.8)	($45.4)	$9.7	$0.1	($35.5)
Dec	($70.4)	$22.9	($1.8)	($49.4)	($75.1)	$12.4	$0.8	($61.9)
Total	($640.6)	$184.0	($9.8)	($466.3)	($648.5)	$166.2	$7.1	($475.2)

Figure 11-8 shows PJM monthly energy costs for January 1, 2008 through December 31, 2017.

Figure 11-8 PJM monthly energy costs (Millions): 2008 through 2017

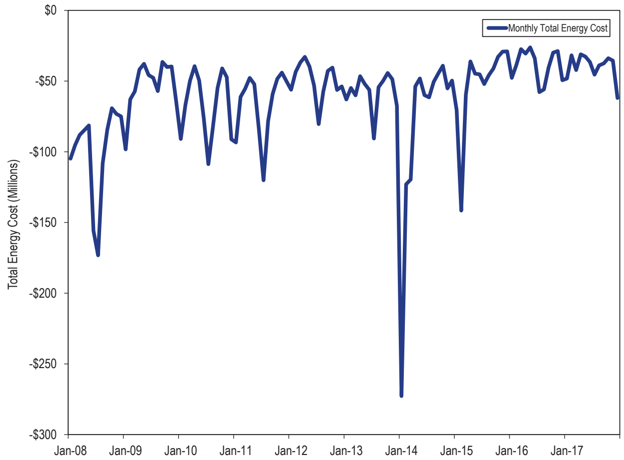


Table 11-50 and Table 11-51 show the monthly total energy costs for each virtual transaction type in 2017 and 2016. In 2017, DECs paid $1,092.8 million in energy costs in the day-ahead market, were paid $1,095.6 million in energy credits in the balancing energy market and were paid $2.9 million in net payment for energy. In 2017, INCs were paid $1,183.6 million in energy credits in the day-ahead market, paid $1,175.3 million in energy costs in the balancing market and received $8.2 million in net payment for energy. In 2016, DECs paid $1,254.0 million in energy costs in the day-ahead market, were paid $1,239.3 million in energy credits in the balancing energy market and paid $14.7 million in net payment for energy. In 2016, INCs were paid $1,275.2 million in energy credits in the day-ahead market, paid $1,250.4 million in energy cost in the balancing energy market and received $24.8 million in net payment for energy.

Table 11-50 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Total	DEC	INC	Total	Grand Total
Jan	$115.3	($134.8)	($19.5)	($116.4)	$135.6	$19.2	($0.3)
Feb	$82.8	($107.0)	($24.2)	($79.8)	$103.3	$23.5	($0.7)
Mar	$123.9	($150.0)	($26.1)	($124.5)	$149.2	$24.7	($1.4)
Apr	$109.6	($106.8)	$2.9	($104.2)	$102.0	($2.2)	$0.7
May	$112.6	($123.9)	($11.3)	($114.0)	$124.9	$10.9	($0.4)
Jun	$88.3	($77.5)	$10.8	($87.2)	$76.6	($10.6)	$0.2
Jul	$90.2	($92.9)	($2.7)	($93.2)	$95.0	$1.8	($0.9)
Aug	$68.5	($70.2)	($1.6)	($66.9)	$68.5	$1.5	($0.1)
Sep	$81.6	($72.7)	$8.9	($88.6)	$73.8	($14.8)	($6.0)
Oct	$68.6	($83.7)	($15.1)	($66.5)	$81.1	$14.6	($0.5)
Nov	$59.5	($75.3)	($15.8)	($57.0)	$72.7	$15.8	($0.0)
Dec	$91.9	($88.8)	$3.0	($97.3)	$92.6	($4.7)	($1.6)
Total	$1,092.8	($1,183.6)	($90.8)	($1,095.6)	$1,175.3	$79.7	($11.1)

Table 11-51 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2016

	Energy Costs (Millions)						
	Day-Ahead			Balancing			
	DEC	INC	Total	DEC	INC	Total	Grand Total
Jan	$102.0	($109.3)	($7.2)	($101.0)	$106.1	$5.1	($2.1)
Feb	$85.5	($87.5)	($2.1)	($81.3)	$84.3	$3.0	$1.0
Mar	$68.6	($100.2)	($31.6)	($63.8)	$93.0	$29.2	($2.4)
Apr	$84.9	($109.3)	($24.3)	($86.5)	$112.0	$25.6	$1.2
May	$78.3	($87.2)	($8.9)	($79.4)	$86.1	$6.8	($2.1)
Jun	$105.0	($91.0)	$14.0	($110.0)	$94.5	($15.5)	($1.5)
Jul	$139.7	($130.5)	$9.2	($128.9)	$119.4	($9.6)	($0.3)
Aug	$138.1	($119.8)	$18.3	($145.6)	$123.4	($22.2)	($3.8)
Sep	$124.7	($104.7)	$20.0	($124.3)	$104.0	($20.4)	($0.3)
Oct	$111.4	($110.5)	$1.0	($107.4)	$106.9	($0.5)	$0.5
Nov	$84.6	($100.7)	($16.1)	($82.9)	$98.5	$15.6	($0.6)
Dec	$131.2	($124.7)	$6.5	($128.2)	$122.2	($6.1)	$0.4
Total	$1,254.0	($1,275.2)	($21.2)	($1,239.3)	$1,250.4	$11.1	($10.2)