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). 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.[1]

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.[2] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation.

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.[3]

This report, for the first time, provides two measures of local congestion: Area Based Congestion and Constraint Based Congestion. Total congestion is the same for both measures. Local congestion differs between the two measures.

Area Based Congestion is defined as the total congestion payments by load at the buses within a defined area, typically a zone, minus the total congestion credits received by generation at the buses in the same defined area.

Constraint Based Congestion is defined as the total congestion payments by load at the buses within a defined area minus total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of location in the PJM system.

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

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

3 The total congestion and marginal losses were calculated as of October 24, 2018, and are subject to change, based on continued PJM billing updates.

The MMU has previously reported zonal Area Based Congestion in the congestion appendix.[4] By including only generation credits received by generation within a defined area, Area Based Congestion calculations ignore credits associated with generation outside of the defined area that may, based on unit offers and transmission system capability, be supplying a portion of the load in the area. Total Area Based Congestion is the sum of all congestion for generators and load and virtuals with market activity at the buses in each zone in PJM.

Constraint Based Congestion reflects differences between credits and charges caused by binding transmission limits on power flow from generators, regardless of location, to load in a specific area. Total Constraint Based Congestion is the sum of all congestion for generators and load and virtuals with market activity at the buses in each zone in PJM.

Constraint Based Congestion is a more accurate measure of local congestion, which is the difference between load charges and generation credits caused by transmission constraints that provide access to low cost generation and require the use of higher cost local generation. Constraint Based Congestion reflects the underlying characteristics of the complete power system as it affects the defined area, 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.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $660.8 million or 145.1 percent, from $455.4 million in the first nine months of 2017 to $1,116.2 million in the first nine months of 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $669.2 million or 138.7 percent, from $482.5 million in the first nine months of 2017 to $1,151.7 million in the first nine months of 2018.
- **Balancing Congestion.** Negative balancing congestion costs increased by $8.4 million or 30.8 percent, from -$27.1 million in the first nine months of 2017 to -$35.5 million in the first nine months of 2018. Negative balancing explicit costs decreased by $3.1 million or 46.3 percent, from -$6.7 million in the first nine months of 2017 to -$3.6 million in the first nine months of 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $729.1 million or 136.6 percent, from $533.8 million in the first nine months of 2017 to $1,262.9 million in the first nine months of 2018.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2018 ranged from $45.2 million in February to $535.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AEP - DOM Interface, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, 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 the first nine months of 2018. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  But day-ahead congestion frequency decreased by 53.0 percent from 224,543 congestion event hours in the first nine months of 2017 to 105,437 congestion event hours in the first nine months of 2018 as a result of a significant decrease in up to congestion transaction (UTC) activities in response to the February 20, 2018, FERC order that limited UTC trading, effective February 22, 2018, to hubs, residual metered load, and interfaces.[5]

  Real-time congestion frequency increased by 2.7 percent from 16,473 congestion event hours in the first nine months of 2017 to 16,924 congestion event hours in the first nine months of 2018.

4 See the *2017 State of the Market Report for PJM*, Vol. 2, Appendix G "Congestion and Marginal Losses."

5 162 FERC ¶ 61,139.

- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018 FERC order.

  The AEP - DOM Interface was the largest contributor to congestion costs in the first nine months of 2018. With $120.4 million in total congestion costs, it accounted for 10.8 percent of the total PJM congestion costs in the first nine months of 2018.

- **Zonal Congestion.** Using the constraint based measure, Dominion had the largest local congestion costs among all control zones in the first nine months of 2018. Dominion had $206.6 million in local congestion costs, comprised of $199.4 million in local day-ahead congestion costs and $7.2 million in local balancing congestion costs. The AEP - DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the AP South Interface and the Person – Sedge Hill Line contributed $138.5 million, or 67.0 percent of the local Dominion control zone congestion costs. Using the less accurate area based measure, AEP had the largest local congestion costs among all control zones in the first nine months of 2018. AEP had $304.6 million in local congestion costs, comprised of $335.8 million in total day-ahead congestion costs and -$31.2 million in total balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $255.9 million or 51.1 percent, from $501.0 million in the first nine months of 2017 to $757.0 million in the first nine months of 2018. The loss MWh in PJM increased by 823.7 GWh or 7.5 percent, from 11,036.7 GWh in the first nine months of 2017 to 11,860.3 GWh in the first nine months of 2018. The loss component of real-time LMP in the first nine months of 2018 was $0.02, compared to $0.01 in the first nine months of 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first nine months of 2018 ranged from $49.5 million in February to $222.8 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $214.8 million or 38.0 percent, from $566.0 million in the first nine months of 2017 to $780.9 million in the first nine months of 2018.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $41.1 million or 63.2 percent, from -$65.0 million in the first nine months of 2017 to -$23.9 million in the first nine months of 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in the first nine months of 2018 by $99.9 million or 63.9 percent, from $156.5 million in the first nine months of 2017, to $256.4 million in the first nine months of 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $154.7 million or 45.0 percent, from -$344.0 million in the first nine months of 2017 to -$498.7 million in the first nine months of 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $67.1 million or 13.8 percent, from -$484.4 million in the first nine months of 2017 to -$551.4 million in the first nine months of 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $88.8 million or 65.4 percent, from $135.9 million in the first nine months of 2017 to $47.1 million in the first nine months of 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

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.

Total congestion in the first nine months of 2018 increased significantly from the first nine months of 2017. The increase was a result of an increase in day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

Balancing explicit congestion increased by $3.1 million or 46.3 percent, from -$6.7 million in the first nine months of 2017 to -$3.6 million in the first nine months of 2018. The increase in balancing explicit costs was the result of an increase in balancing explicit congestion caused by up to congestion (UTCs) which went from -$7.0 million in the first nine months of 2017 to $6.3 million in the first nine months of 2018.

The monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018. The balancing congestion costs were -$16.0 million and -$19.9 million in May and June. The large negative balancing congestion cost was caused in large part by UTCs profiting from day-ahead and real-time market modeling differences, including a number of constraints that were modeled in real-time market but not modeled in day-ahead market.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

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 65.3, 90.3, 100.0, 50.0 and 87.6 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 and the first four months of 2018/2019 planning periods.

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.[6] 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-

6 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>.

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.[7] 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. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost 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. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for January through September, 2008 through 2018.[8]

The load-weighted average real-time LMP increased $9.08 or 29.9 percent from $30.36 in the first nine months of 2017 to $39.43 in the first nine months of 2018. The load-weighted average congestion component increased by $0.02 from $0.02 in the first nine months of 2017 to $0.04 in the first nine months of 2018. The load-weighted average loss component in the first nine months of 2018 was $0.02 compared to $0.01 in the first nine months of 2017. The load-weighted average energy component increased by $9.05 or 29.8 percent from $30.32 in the first nine months of 2017 to $39.37 in the first nine months of 2018.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2018[9]

(Jan - Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$77.27	$77.15	$0.07	$0.05
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02
2015	$38.94	$38.89	$0.03	$0.02
2016	$29.32	$29.27	$0.04	$0.02
2017	$30.36	$30.32	$0.02	$0.01
2018	$39.43	$39.37	$0.04	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for January through September, 2008 through 2018.[10] The load-weighted average day-ahead LMP increased $8.45, or 27.9 percent, from $30.26 in the first nine months of 2017 to $38.71 in the first nine months of 2018. The load-weighted average congestion component increased $0.08 from $0.04 in the first nine months of 2017 to $0.12 in the first nine months of 2018. The load-weighted average loss component increased from -$0.02 in the first nine months of 2017 to -$0.01 in the first nine months of 2018. The load-weighted average energy component increased $8.37, or 27.7 percent, from $30.24 in the first nine months of 2017 to $38.60 in the first nine months of 2018.

7 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.

8 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.

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

10 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 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2008 through 2018

(Jan - Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$75.96	$76.30	($0.09)	($0.24)
2009	$39.35	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)
2015	$39.51	$39.25	$0.28	($0.02)
2016	$29.69	$29.54	$0.17	($0.01)
2017	$30.26	$30.24	$0.04	($0.02)
2018	$38.71	$38.60	$0.12	($0.01)

Table 11-3 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours. In the first nine months of 2018, January had the highest real-time, load-weighted average LMP in constrained hours as a result of cold weather and high gas prices in early January 2018.

Table 11-3 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2017 through September 2018

	2017		2018	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$32.96	$26.37	$96.69	$24.03
Feb	$25.82	$24.26	$27.00	$23.93
Mar	$32.56	$26.54	$33.35	$23.64
Apr	$29.26	$23.90	$35.74	$24.92
May	$32.27	$23.90	$38.78	$17.24
Jun	$29.23	$18.80	$34.55	$21.81
Jul	$34.22	$26.33	$37.08	$26.09
Aug	$28.39	$24.66	$38.64	$25.11
Sep	$33.79	$21.28	$36.83	$26.29
Oct	$28.69	$29.20		
Nov	$29.43	$23.26		
Dec	$44.60	$24.74		
Avg	$31.81	$24.42	$42.91	$24.58

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2017 and 2018. In the first nine months of 2018, BGE had the highest real-time congestion component of all control zones, $4.85, and ComEd had the lowest real-time congestion component, -$6.42.

Table 11-4 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)				2018 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$28.38	$30.48	($2.49)	$0.39	$37.27	$38.62	($2.30)	$0.95
AEP	$30.15	$30.14	$0.27	($0.26)	$38.79	$39.38	($0.02)	($0.57)
APS	$30.56	$30.22	$0.33	$0.01	$41.51	$39.74	$1.51	$0.26
ATSI	$31.19	$30.16	$0.46	$0.58	$41.48	$38.63	$2.31	$0.55
BGE	$33.73	$30.56	$2.18	$0.99	$46.51	$40.19	$4.85	$1.47
ComEd	$28.64	$30.30	($0.67)	($1.00)	$29.97	$38.39	($6.42)	($1.99)
DAY	$31.14	$30.30	$0.32	$0.52	$39.98	$39.27	$0.11	$0.60
DEOK	$30.68	$30.29	$1.07	($0.68)	$40.56	$39.21	$2.38	($1.04)
DLCO	$30.58	$30.27	$0.43	($0.11)	$41.19	$38.71	$2.38	$0.10
Dominion	$32.19	$30.49	$1.39	$0.32	$45.28	$40.45	$4.28	$0.54
DPL	$30.36	$30.59	($0.93)	$0.70	$44.03	$40.44	$1.76	$1.82
EKPC	$29.25	$30.49	($0.50)	($0.74)	$36.98	$41.38	($2.99)	($1.41)
JCPL	$29.72	$30.78	($1.33)	$0.26	$38.10	$39.14	($1.83)	$0.79
Met-Ed	$30.32	$30.32	($0.17)	$0.17	$37.97	$39.28	($1.79)	$0.48
PECO	$28.42	$30.40	($2.01)	$0.04	$37.63	$39.24	($2.16)	$0.55
PENELEC	$29.28	$29.95	($0.87)	$0.19	$38.83	$38.82	($0.43)	$0.45
Pepco	$32.63	$30.51	$1.50	$0.63	$44.76	$39.96	$3.82	$0.99
PPL	$28.85	$30.23	($1.35)	($0.04)	$37.33	$39.63	($2.46)	$0.15
PSEG	$29.38	$30.36	($1.23)	$0.25	$37.70	$38.56	($1.61)	$0.75
RECO	$30.02	$30.88	($1.19)	$0.32	$38.30	$38.78	($1.18)	$0.70
PJM	$30.36	$30.32	$0.02	$0.01	$39.43	$39.37	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-5 for January through September, 2017 and 2018. In the first nine months of 2018, BGE had the highest day-ahead congestion component of all control zones, $5.04, and ComEd had the lowest day-ahead congestion component, -$6.23.

Table 11-5 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)				2018 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$28.37	$30.42	($2.25)	$0.19	$36.95	$38.13	($1.72)	$0.55
AEP	$30.23	$30.16	$0.32	($0.24)	$37.90	$38.67	($0.32)	($0.46)
APS	$30.47	$30.15	$0.36	($0.04)	$40.21	$38.67	$1.34	$0.20
ATSI	$30.86	$30.08	$0.38	$0.40	$39.53	$37.94	$1.06	$0.54
BGE	$33.93	$30.55	$2.48	$0.90	$45.54	$39.22	$5.04	$1.28
ComEd	$28.50	$30.20	($0.97)	($0.73)	$29.80	$37.71	($6.23)	($1.68)
DAY	$31.05	$30.24	$0.26	$0.55	$39.43	$38.50	$0.21	$0.72
DEOK	$30.70	$30.30	$0.88	($0.49)	$41.25	$38.41	$3.48	($0.63)
DLCO	$30.40	$30.24	$0.39	($0.22)	$39.70	$38.10	$1.49	$0.11
Dominion	$32.49	$30.51	$1.60	$0.37	$44.78	$39.68	$4.52	$0.57
DPL	$30.36	$30.58	($0.62)	$0.40	$42.98	$39.75	$1.94	$1.30
EKPC	$29.72	$30.63	($0.19)	($0.72)	$36.25	$40.66	($3.17)	($1.24)
JCPL	$29.29	$30.55	($1.38)	$0.12	$37.44	$38.42	($1.44)	$0.46
Met-Ed	$29.81	$30.21	($0.37)	($0.03)	$37.51	$38.34	($0.90)	$0.06
PECO	$28.08	$30.18	($1.99)	($0.11)	$36.96	$38.35	($1.58)	$0.20
PENELEC	$29.19	$29.95	($0.76)	$0.00	$37.95	$38.50	($0.76)	$0.21
Pepco	$32.78	$30.36	$1.81	$0.61	$44.15	$39.16	$4.02	$0.96
PPL	$28.54	$30.09	($1.31)	($0.24)	$36.66	$38.61	($1.69)	($0.27)
PSEG	$29.43	$30.33	($1.09)	$0.18	$37.97	$38.22	($0.77)	$0.53
RECO	$29.76	$30.60	($1.06)	$0.22	$38.05	$38.27	($0.72)	$0.49
PJM	$30.26	$30.24	$0.04	($0.02)	$38.71	$38.60	$0.12	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for the first nine months of 2017 and 2018.[11]

Table 11-6 Hub real-time, average LMP components (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)				2018 (Jan - Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.80	$28.76	$0.08	($1.04)	$33.33	$36.46	($1.62)	($1.50)
AEP-DAY Hub	$28.77	$28.76	$0.36	($0.34)	$34.77	$36.46	($1.02)	($0.67)
ATSI Gen Hub	$29.14	$28.76	$0.31	$0.07	$37.33	$36.46	$1.07	($0.20)
Chicago Gen Hub	$26.43	$28.76	($1.01)	($1.32)	$27.81	$36.46	($6.31)	($2.34)
Chicago Hub	$27.14	$28.76	($0.71)	($0.90)	$28.36	$36.46	($6.27)	($1.83)
Dominion Hub	$29.96	$28.76	$1.09	$0.12	$40.41	$36.46	$3.76	$0.19
Eastern Hub	$28.40	$28.76	($0.92)	$0.57	$37.96	$36.46	$0.13	$1.37
N Illinois Hub	$26.77	$28.76	($0.93)	($1.06)	$28.15	$36.46	($6.29)	($2.02)
New Jersey Hub	$27.30	$28.76	($1.62)	$0.16	$34.96	$36.46	($2.11)	$0.62
Ohio Hub	$28.90	$28.76	$0.42	($0.27)	$34.50	$36.46	($1.29)	($0.68)
West Interface Hub	$29.30	$28.76	$0.72	($0.17)	$38.87	$36.46	$2.74	($0.33)
Western Hub	$28.78	$28.76	$0.02	$0.01	$37.64	$36.46	$1.02	$0.17

The day-ahead components of LMP for each hub are presented in Table 11-7 for the first nine months of 2017 and 2018.

Table 11-7 Hub day-ahead, average LMP components (Dollars per MWh): January through September, 2017 and 2018

	2017 (Jan - Sep)				2018 (Jan - Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.99	$28.89	$0.09	($0.99)	$33.09	$35.96	($1.54)	($1.33)
AEP-DAY Hub	$28.88	$28.89	$0.33	($0.34)	$34.52	$35.96	($0.90)	($0.55)
ATSI Gen Hub	$29.05	$28.89	$0.21	($0.05)	$36.16	$35.96	$0.30	($0.10)
Chicago Gen Hub	$26.44	$28.89	($1.37)	($1.08)	$27.58	$35.96	($6.33)	($2.05)
Chicago Hub	$27.20	$28.89	($1.05)	($0.64)	$28.18	$35.96	($6.26)	($1.52)
Dominion Hub	$30.32	$28.89	$1.25	$0.18	$39.99	$35.96	$3.76	$0.27
Eastern Hub	$28.70	$28.89	($0.57)	$0.38	$37.69	$35.96	$0.69	$1.04
N Illinois Hub	$26.91	$28.89	($1.15)	($0.83)	$27.94	$35.96	($6.28)	($1.75)
New Jersey Hub	$27.64	$28.89	($1.35)	$0.10	$35.09	$35.96	($1.26)	$0.38
Ohio Hub	$28.94	$28.89	$0.34	($0.29)	$34.32	$35.96	($1.08)	($0.56)
West Interface Hub	$29.50	$28.89	$0.82	($0.21)	$37.92	$35.96	$2.21	($0.25)
Western Hub	$28.93	$28.89	$0.21	($0.18)	$37.02	$35.96	$0.96	$0.09

11 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time load-weighted average of the hourly components of LMP.

Component Costs

Table 11-8 shows the total energy, loss and congestion component costs and the total PJM billing for January through September, 2008, through 2018. These totals are actually net energy, loss and congestion costs. Total congestion cost and marginal loss cost increased in the first nine months of 2018 compared to the first nine months of 2017.

Table 11-8 Total PJM costs by component (Dollars (Millions)): January through September, 2008 through 2018[12 13]

	Component Costs (Millions)					
(Jan - Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2008	($976)	$2,049	$1,778	$2,851	$26,979	10.6%
2009	($485)	$992	$544	$1,051	$19,927	5.3%
2010	($619)	$1,259	$1,134	$1,775	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%
2013	($527)	$797	$510	$779	$25,153	3.1%
2014	($834)	$1,243	$1,705	$2,115	$40,770	5.2%
2015	($537)	$830	$1,143	$1,436	$33,710	4.3%
2016	($358)	$542	$822	$1,006	$29,490	3.4%
2017	($344)	$501	$455	$612	$29,510	2.1%
2018	($499)	$757	$1,116	$1,375	$37,950	3.6%

Congestion

Congestion Accounting

Total congestion costs equal net congestion costs plus explicit congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point to point energy transactions. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[14] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

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

13 Total PJM billing is provided by PJM.

14 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.

Prior to April 1, 2018, implicit balancing congestion costs calculated at the zonal and aggregate level were determined by bus specific deviations between day ahead and real time MWh priced at the bus specific congestion price in the Real-Time Energy Market. As of April 1, 2018, with the introduction of five minute settlement, implicit zonal and aggregate balancing congestion costs are determined by netting the bus specific hourly deviations across every bus in a zone or aggregate and pricing the resulting deviation in zone or aggregate total deviations at the zonal or aggregate congestion price in the Real-Time Energy Market.

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.

Total congestion costs equal load congestion payments netted against generation congestion credits on an hourly basis, by billing organization, and 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.[15]

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 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 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.[16]

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

15 OA Schedule 1 §3.7.

16 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>.

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. This logic is not the correct way to account for the congestion payments by load in an area, which are the total difference between energy payments paid by load in that area and energy revenue received by generators serving that load, regardless of whether they are in the same area.

Total Congestion

Total congestion costs in PJM in the first nine months of 2018 were $1,116.2 million, which were comprised of load congestion payments of $267.2 million, generation credits of -$881.9 million and explicit congestion of -$32.9 million.

Table 11-9 shows total congestion for January through September, 2008 through 2018. 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.[17] [18]

Table 11-9 Total PJM congestion component costs (Dollars (Millions)): January through September, 2008 through 2018

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778	NA	$26,979	6.6%
2009	$544	(69.4%)	$19,927	2.7%
2010	$1,134	108.7%	$26,249	4.3%
2011	$875	(22.9%)	$28,836	3.0%
2012	$425	(51.4%)	$22,119	1.9%
2013	$510	19.9%	$25,153	2.0%
2014	$1,705	234.6%	$40,770	4.2%
2015	$1,143	(33.0%)	$33,710	3.4%
2016	$822	(28.1%)	$29,490	2.8%
2017	$455	(44.6%)	$29,510	1.5%
2018	$1,116	145.1%	$37,950	2.9%

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

18 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-10 shows total congestion by day-ahead and balancing component for the January through September period, by year. Table 11-11 and Table 11-12 show that the increase in balancing explicit costs was the result of an increase in balancing explicit congestion caused by up to congestion (UTCs) which went from -$7.0 million in the first nine months of 2017 to $6.3 million in the first nine months of 2018. The market results were affected by modelling differences between the day-ahead and real-time market models and large CLMP differences resulting from high gas prices from January 5, 2018, through January 8, 2018, and from the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

Table 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through September, 2008 through 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.2)	$0.0	$1,705.4
2015	$539.3	($783.2)	$24.6	$1,347.1	$11.4	$69.9	($145.6)	($204.1)	$0.0	$1,143.0
2016	$313.0	($529.0)	$35.7	$877.8	$1.9	$20.0	($37.3)	($55.5)	($0.0)	$822.2
2017	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4
2018	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2

Table 11-11 and Table 11-12 show the total congestion costs for each transaction type in the first nine months of 2018 and 2017. Table 11-11 shows that in the first nine months of 2018 DECs paid $18.0 million in congestion costs in the day-ahead market, were paid $23.2 million in congestion credits in the balancing energy market, and were paid $5.2 million in total congestion credits. In the first nine months of 2018, INCs paid $18.8 million in congestion charges in the day-ahead market, were paid $26.5 million in congestion credits in the balancing energy market and received $7.6 million in total congestion credits. In the first nine months of 2018, up to congestion (UTCs) were paid $29.6 million in congestion credits in the day-ahead market, paid $6.3 million in congestion charges in the balancing market and were paid $23.2 million in total congestion credits.

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through September, 2018

	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	$18.0	$0.0	$0.0	$18.0	($23.2)	$0.0	$0.0	($23.2)	$0.0	($5.2)
Demand	$53.9	$0.0	$0.0	$53.9	$51.6	$0.0	$0.0	$51.6	$0.0	$105.5
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	$1.6	$1.6	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.9
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($51.3)	$0.0	($0.9)	($52.2)	($12.4)	$0.0	($5.7)	($18.1)	$0.0	($70.3)
Generation	$0.0	($1,135.2)	$0.0	$1,135.2	$0.0	$62.6	$0.0	($62.6)	$0.0	$1,072.6
Grandfathered Overuse	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Import	$0.0	($6.5)	$0.0	$6.5	$0.0	($41.3)	($3.1)	$38.2	$0.0	$44.6
INC	$0.0	($18.8)	$0.0	$18.8	$0.0	$26.5	$0.0	($26.5)	$0.0	($7.6)
Internal Bilateral	$228.4	$228.6	$0.2	($0.0)	$3.1	$3.1	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($29.6)	($29.6)	$0.0	$0.0	$6.3	$6.3	$0.0	($23.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.4)	$0.3	$0.0	$0.3
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.0	$0.0	($0.8)	$0.0	($0.8)
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2

Table 11-12 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through September, 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	($1.3)	$0.0	$0.0	($1.3)	($7.9)	$0.0	$0.0	($7.9)	$0.0	($9.3)
Demand	$24.3	$0.0	$0.0	$24.3	$24.0	$0.0	$0.0	$24.0	$0.0	$48.4
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	($23.1)	$0.0	($0.3)	($23.4)	($3.1)	$0.0	$1.7	($1.3)	$0.0	($24.8)
Generation	$0.0	($478.1)	$0.0	$478.1	$0.0	$24.8	$0.0	($24.8)	$0.0	$453.3
Grandfathered Overuse	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.4)
Import	$0.0	$0.6	$0.0	($0.6)	$0.0	($3.7)	($1.0)	$2.7	$0.0	$2.1
INC	$0.0	($2.7)	$0.0	$2.7	$0.0	$12.3	$0.0	($12.3)	$0.0	($9.6)
Internal Bilateral	$105.4	$105.2	($0.2)	($0.0)	($0.5)	($0.5)	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$1.7	$1.7	$0.0	$0.0	($7.0)	($7.0)	$0.0	($5.3)
Wheel In	$0.0	($0.1)	$0.1	$0.2	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.3
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.1)	$0.0	($0.3)
Total	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4

Table 11-13 shows the change in total congestion cost incurred by transaction type from the first nine months of 2017 to the first nine months of 2018. Total congestion cost incurred by generation increased by $619.3 million, and total congestion cost incurred by demand increased by $57.2 million.

The total congestion payments to up to congestion transactions (UTCs) increased by $17.9 million, from $5.3 million in the first nine months of 2017 to $23.2 million in the first nine months of 2018. Total day-ahead congestion costs payments to UTCs increased by $31.3 million from -$1.7 million in the first nine months of 2017 to $29.6 million in the first nine months of 2018. In other words, UTCs paid $1.7 million in congestion charges in the first nine months of 2017 and were paid $29.6 million in congestion credits in the first nine months of 2018 in the day-ahead market. Over the same period balancing congestion costs paid by UTCs increased by $13.4 million, from -$7.0 million in the first nine months of 2017 to $6.3 million in the first nine months of 2018.

Table 11-13 Change in total PJM congestion costs by transaction type by market: January through September, 2017 to 2018 (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	$19.4	$0.0	$0.0	$19.4	($15.3)	$0.0	$0.0	($15.3)	$0.0	$4.1
Demand	$29.6	$0.0	$0.0	$29.6	$27.5	$0.0	$0.0	$27.5	$0.0	$57.2
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	$0.5	$0.5	$0.0	$0.0	($0.7)	($0.7)	$0.0	($0.2)
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($28.2)	$0.0	($0.6)	($28.8)	($9.4)	$0.0	($7.4)	($16.8)	$0.0	($45.6)
Generation	$0.0	($657.1)	$0.0	$657.1	$0.0	$37.8	$0.0	($37.8)	$0.0	$619.3
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.4	$0.4	$0.0	($0.1)
Import	$0.0	($7.1)	$0.0	$7.1	$0.0	($37.6)	($2.2)	$35.5	$0.0	$42.6
INC	$0.0	($16.1)	$0.0	$16.1	$0.0	$14.1	$0.0	($14.1)	$0.0	$2.0
Internal Bilateral	$123.0	$123.3	$0.3	$0.0	$3.5	$3.5	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	($31.3)	($31.3)	$0.0	$0.0	$13.4	$13.4	$0.0	($17.9)
Wheel In	$0.0	$0.1	($0.1)	($0.2)	$0.0	($0.6)	($0.4)	$0.2	$0.0	$0.0
Wheel Out	$0.1	$0.0	$0.0	$0.1	($0.6)	$0.0	$0.0	($0.6)	$0.0	($0.5)
Total	$143.9	($556.8)	($31.5)	$669.2	$5.8	$17.2	$3.1	($8.4)	$0.0	$660.8

Zonal Congestion

Area Based Congestion

When summed across a zone, the net congestion bill shows the overall congestion charge or credit for the buses in that zone, not including explicit congestion.

Because the net congestion bill for a zone only includes charges or credits incurred in the zone, the congestion bill for the zone is not a good measure of the amount of congestion (the difference between what load pays and generation is paid) paid by the load in that zone. Zonal congestion calculations do not, for example, account for the total difference between what the zonal load is paying in congestion charges relative to what the generation is paid that serves that load if the zone is a net importer or a net exporter of generation. Zonal congestion calculated for a zone that is a net importer of generation will tend to have overstated congestion, as the calculation does not account for external generation credits from external generation used to serve that load. Zonal congestion calculated for a zone that is a net exporter of generation will tend to have overstated generation congestion credits, as the calculation does not account for only the generation used to meet the zone's internal load.

Constraint Based Congestion

The Constraint Based Congestion calculation corrects the shortcomings of the Area Based Congestion approach. Constraint Based Congestion includes all energy charges or credits incurred to serve load in the zone. Constraint Based Congestion is the congestion paid by that zone's load. Constraint Based Congestion calculations account for the total difference between what the zonal load pays in congestion charges net of what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Constraint Based Congestion calculates congestion on a constraint by constraint basis. On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation. Transmission constraints cause price separation (differences in LMP), defined by the marginal cost of resolving the constraint given the need to meet power balance requirements, indicated by the shadow price of the constraint. The LMP at any point is equal to the system marginal price (SMP) plus the shadow price of the constraint times the DFAX of the binding constraint to the bus in question (the CLMP of the constraint at that bus).

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific congestion is allocated to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-14 provides the Area Based and Constraint Based day ahead and balancing congestion by zone for the first nine months of 2018 and Table 11-15 shows the area based and constraint based congestion costs by zone for the first nine months of 2017.

Table 11-14 Area Based and Constraint Based total day-ahead and total balancing congestion by zone (Dollars (Millions)): January through September, 2018

	Congestion Costs (Millions)					
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	($1.1)	($2.4)	($3.5)	$9.6	($0.6)	$9.0
AEP	$335.8	($31.2)	$304.6	$187.1	$1.0	$188.1
APS	$51.2	($1.4)	$49.9	$51.6	$1.9	$53.5
ATSI	$80.1	($19.0)	$61.1	$81.0	($0.3)	$80.7
BGE	$52.0	($0.7)	$51.3	$61.9	$1.7	$63.6
ComEd	$157.7	$44.0	$201.7	$62.2	($47.0)	$15.2
DAY	$13.1	($1.4)	$11.7	$33.2	$0.7	$33.9
DEOK	$70.7	($9.3)	$61.5	$120.4	$6.5	$126.9
DLCO	$5.4	$0.9	$6.3	$15.6	$1.1	$16.7
Dominion	$80.1	($5.0)	$75.0	$199.4	$7.2	$206.6
DPL	$31.6	$3.0	$34.6	$61.6	$1.2	$62.8
EKPC	($17.2)	$4.7	($12.5)	$11.7	($2.0)	$9.7
EXT	($1.6)	($4.5)	($6.1)	$0.7	($0.0)	$0.7
JCPL	$22.9	($13.6)	$9.2	$23.0	($1.4)	$21.6
Met-Ed	$27.8	($5.1)	$22.7	$30.3	($1.3)	$28.9
PECO	$81.6	$0.7	$82.3	$34.8	($1.7)	$33.1
PENELEC	$61.6	($4.0)	$57.6	$21.3	$0.7	$22.0
Pepco	$44.3	$3.8	$48.1	$50.6	$1.5	$52.1
PPL	$10.9	$11.7	$22.6	$39.1	($3.2)	$36.0
PSEG	$45.4	($6.0)	$39.4	$53.3	($1.2)	$52.0
RECO	($0.7)	($0.6)	($1.2)	$3.2	($0.0)	$3.2
Total	$1,151.7	($35.5)	$1,116.2	$1,151.7	($35.5)	$1,116.2

Table 11-15 Area Based and Constraint Based total day-ahead and total balancing congestion by zone (Dollars (Millions)): January through September, 2017

	Congestion Costs (Millions)					
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	($3.3)	($1.1)	($4.3)	$2.3	($0.6)	$1.7
AEP	$52.4	$5.7	$58.0	$73.3	($2.0)	$71.3
APS	$10.6	$0.3	$10.9	$15.2	($1.5)	$13.7
ATSI	$21.7	($6.6)	$15.1	$19.6	($0.1)	$19.5
BGE	$32.6	($2.5)	$30.1	$27.6	$0.2	$27.8
ComEd	$159.2	($10.9)	$148.4	$129.7	($20.1)	$109.6
DAY	$0.7	$0.8	$1.4	$5.0	($0.0)	$5.0
DEOK	$11.5	$2.6	$14.1	$17.6	$1.5	$19.1
DLCO	($0.4)	($0.3)	($0.7)	$3.1	($0.2)	$2.9
Dominion	$35.0	($7.2)	$27.8	$60.8	($1.6)	$59.2
DPL	($4.3)	$4.7	$0.4	$18.6	$2.7	$21.4
EKPC	($2.4)	$1.4	($0.9)	$3.2	($1.5)	$1.7
EXT	($13.3)	($11.5)	($24.8)	($0.2)	($0.0)	($0.2)
JCPL	$3.2	$0.0	$3.2	$8.8	($0.5)	$8.3
Met-Ed	$12.7	$1.3	$14.0	$11.9	$1.4	$13.3
PECO	$59.5	($4.5)	$55.1	$13.5	($1.8)	$11.7
PENELEC	$37.4	($7.3)	$30.1	$10.3	($1.6)	$8.7
Pepco	$22.4	$3.3	$25.7	$20.2	($0.2)	$19.9
PPL	$21.0	$3.5	$24.5	$17.6	($0.3)	$17.3
PSEG	$27.5	$0.9	$28.5	$23.6	($0.8)	$22.8
RECO	($1.3)	$0.1	($1.2)	$0.8	($0.0)	$0.7
Total	$482.5	($27.1)	$455.4	$482.5	($27.1)	$455.4

Monthly Congestion

Table 11-16 shows that monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018.

The total day-ahead congestion costs from January 5, through January 8, 2018, contributed 47.2 percent ($244.5 million out of $517.7 million) of total day-ahead congestion costs in January 2018. The high total day-ahead congestion costs from January 5, 2018 through January 8, 2018, were mainly a result of the high negative generation credits caused by the AEP – DOM Interface, Cloverdale Transformer, Tanners Creek – Miami Fort Flowgate and 5004/5005 Interface constraints. The high gas prices and dispatch of high cost units resulted in high shadow prices for those constraints. The high negative

CLMPs on the low side of those constraints caused high negative day-ahead generation credits on those days. Negative generation credits are positive congestion costs.

Congestion costs in May were the second highest after January. Most of the May congestion costs were in the day-ahead market where the congestion costs were significantly affected by the Graceton – Safe Harbor constraint.

Table 11-16 Monthly PJM congestion costs by market (Dollars (Millions)): January 2017 through September 2018

	Congestion Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.4	($6.5)	($0.0)	$59.9	$517.7	$18.2	$0.0	$535.9
Feb	$44.4	$2.1	$0.0	$46.5	$43.8	$1.4	($0.0)	$45.2
Mar	$54.1	($2.5)	$0.0	$51.6	$80.2	($0.3)	$0.0	$79.9
Apr	$30.7	($0.1)	$0.0	$30.5	$57.4	($3.3)	$0.0	$54.1
May	$36.7	($4.0)	$0.0	$32.7	$122.2	($16.0)	$0.0	$106.2
Jun	$64.5	($0.2)	$0.0	$64.4	$95.2	($19.9)	$0.0	$75.3
Jul	$51.7	($10.4)	$0.0	$41.3	$70.8	($5.8)	$0.0	$65.0
Aug	$34.3	($4.2)	$0.0	$30.1	$69.2	($3.5)	$0.0	$65.7
Sep	$99.7	($1.2)	$0.0	$98.5	$95.2	($6.3)	($0.0)	$88.9
Oct	$50.8	$11.3	$0.0	$62.1				
Nov	$59.9	($1.5)	($0.0)	$58.3				
Dec	$139.8	($18.1)	($0.0)	$121.7				
Total	$733.1	($35.5)	$0.0	$697.6	$1,151.7	($35.5)	$0.0	$1,116.2

Figure 11-1 shows PJM monthly total congestion cost for January 1, 2008 through September 30, 2018.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): January 2008 through September 2018

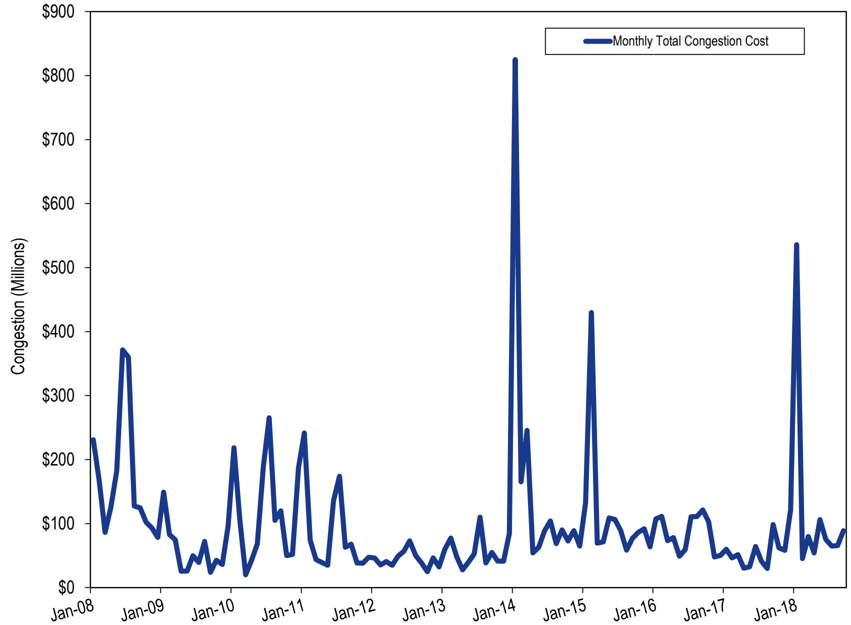


Table 11-17 shows monthly total congestion costs for each virtual transaction type in the first nine months of 2018 and Table 11-18 shows the monthly total congestion costs for each virtual transaction type in 2017. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. The totals in Table 11-17 and Table 11-18 show that virtuals were paid in the first nine months of 2018 and in 2017.

Table 11-17 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through September, 2018

	Congestion Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$4.1	($6.5)	($2.4)	$4.5	($8.1)	($3.6)	($40.8)	$29.5	($11.3)	($17.2)
Feb	$1.8	$0.4	$2.2	$1.2	($0.8)	$0.4	($0.5)	$1.3	$0.9	$3.5
Mar	$0.9	($2.8)	($1.9)	$1.4	($3.2)	($1.8)	($5.1)	$2.0	($3.1)	($6.8)
Apr	$0.4	($0.7)	($0.4)	$1.8	($1.4)	$0.4	($1.0)	$1.0	($0.1)	($0.1)
May	$1.5	($4.1)	($2.6)	$4.5	($6.9)	($2.5)	$1.7	($10.6)	($8.9)	($14.0)
Jun	$3.6	($2.4)	$1.1	$3.0	($3.7)	($0.7)	$5.6	($4.4)	$1.2	$1.6
Jul	$1.3	($2.4)	($1.1)	$0.8	($0.7)	$0.1	$2.3	($2.8)	($0.5)	($1.5)
Aug	$2.4	($3.1)	($0.6)	$0.2	($0.2)	$0.1	$3.4	($2.8)	$0.7	$0.1
Sep	$2.1	($1.6)	$0.5	$1.4	($1.5)	($0.1)	$4.8	($6.9)	($2.1)	($1.7)
Total	$18.0	($23.2)	($5.2)	$18.8	($26.5)	($7.6)	($29.6)	$6.3	($23.2)	($36.1)

Table 11-18 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Congestion Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$1.1	($3.0)	($2.0)	$0.3	($1.1)	($0.8)	$2.9	($2.0)	$1.0	($1.9)
Feb	($0.7)	($1.6)	($2.3)	($4.9)	$3.4	($1.5)	$0.7	$1.7	$2.4	($1.4)
Mar	($1.2)	$0.4	($0.8)	$2.3	($2.6)	($0.3)	($1.4)	$1.2	($0.3)	($1.3)
Apr	($1.5)	$1.3	($0.2)	$0.2	($0.6)	($0.4)	$0.7	$0.6	$1.4	$0.8
May	($3.5)	$1.7	($1.8)	$1.4	($3.2)	($1.8)	$0.2	$0.6	$0.9	($2.7)
Jun	($0.3)	$0.2	($0.2)	$1.0	($1.5)	($0.5)	($0.3)	$1.4	$1.1	$0.4
Jul	$0.6	($2.2)	($1.7)	$1.1	($3.2)	($2.1)	$1.0	($5.1)	($4.1)	($7.9)
Aug	$2.0	($2.1)	($0.1)	$0.4	($1.3)	($0.9)	$1.6	($2.7)	($1.2)	($2.2)
Sep	$2.3	($2.6)	($0.3)	$0.9	($2.2)	($1.3)	($3.8)	($2.7)	($6.5)	($8.1)
Oct	$1.8	($2.5)	($0.7)	($8.6)	$7.6	($1.0)	($3.9)	$3.8	($0.1)	($1.9)
Nov	$2.0	($3.1)	($1.1)	($4.3)	$3.0	($1.3)	$1.0	($2.1)	($1.1)	($3.5)
Dec	$1.9	($3.6)	($1.7)	($0.2)	$1.9	$1.7	($7.6)	($5.5)	($13.1)	($13.1)
Total	$4.3	($17.1)	($12.8)	($10.3)	$0.2	($10.2)	($8.9)	($10.8)	($19.7)	($42.7)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first nine months of 2018, there were 105,437 day-ahead, congestion event hours compared to 224,543 day-ahead congestion event hours in the first nine months of 2017. Of 2018 day-ahead congestion event hours, only 7,789 (7.4 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2018, there were 16,924 real-time, congestion event hours compared to 16,473 real-time, congestion event hours in the first nine months of 2017. Of 2018 real-time congestion event hours, 7,878 (46.5 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $365.5 million, or 32.7 percent, of the total PJM congestion costs in the first nine months of 2018. The top five constraints were the AEP – DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the Tanners Creek – Miami Fort Flowgate, and the 5004/5005 Interface.

The change in the location of the top ten constraints between the first nine months of 2017 and 2018 was a result of the increased gas prices in January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018 (see Figure 11-2).

When gas prices are low compared to coal prices, as they were for the bulk of 2017, generation offers tend to be lower in the eastern and central part of PJM than in the rest of PJM. This causes constraints between the eastern and central part of PJM and the rest of PJM to be the largest contributors to congestion.

When gas prices are high compared to coal prices, as they were in January of 2018, generation offers tend to be lower in the western region of PJM than in the rest of PJM. This causes constraints between western region and the southeast to be the largest contributors to congestion.

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018 FERC order implemented by PJM on February 22, 2018.[19] The order limited UTC trading to hubs, residual metered load, and interfaces.

Real-time, congestion event hours increased on interfaces and lines and decreased on flowgates and transformers. The increase on interfaces was primarily a result of the increase on the AEP - DOM Interface which resulted from high gas prices in January 2018. Increases in gas prices in the PJM Mid-Atlantic Region interacted with flat coal prices in the west to cause west to east congestion in the first nine months of 2018. The decrease in real-time, congestion event hours on flowgates was primarily a result of the fact that none of the NYISO flowgates were binding in the first nine months of 2018.

Day-ahead congestion costs increased on all types of facilities in the first nine months of 2018 compared to the first nine months of 2017. Day-ahead generation credits decreased on all types of facilities in the first nine months of 2018 compared to the first nine months of 2017. The high negative day-ahead generation credits were mainly a result of high gas prices and dispatch of high cost units, which caused high shadow prices for some constraints in the early part of January. The high negative CLMPs on the low side of those constraints caused high negative day-ahead generation credits. Negative generation credits are positive congestion costs.

Balancing congestion costs increased on all types of facilities except lines in the first nine months of 2018 compared to the first nine months of 2017. Table 11-19 provides congestion event hour subtotals and congestion cost subtotals comparing the first nine months of 2018 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[20] [21]

Table 11-20 presents this information for the first nine months of 2017.

Table 11-19 Congestion summary (By facility type): January through September, 2018

	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	($53.0)	($304.7)	($36.7)	$214.9	$1.5	$5.6	$1.4	($2.6)	$212.3	15,659	4,240
Interface	$64.0	($162.8)	($13.9)	$212.9	$15.2	$22.8	$11.1	$3.4	$216.4	2,171	391
Line	$166.2	($344.6)	$18.1	$528.9	($2.0)	$21.0	($15.7)	($38.7)	$490.2	60,750	10,376
Transformer	$59.2	($110.9)	$2.0	$172.2	$0.1	$1.4	$3.1	$1.8	$174.0	23,484	1,344
Other	$12.5	($8.8)	$1.2	$22.4	$3.0	($1.1)	($4.7)	($0.6)	$21.8	3,373	573
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.5	$0.4	$1.2	$1.2	$1.5	NA	NA
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2	105,437	16,924

19 162 FERC ¶ 61,139.

20 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.

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

Table 11-20 Congestion summary (By facility type): January through September, 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	($47.5)	($157.5)	($16.3)	$93.7	$6.4	$7.5	($6.6)	($7.7)	$86.1	19,973	4,751
Interface	$17.0	($12.1)	($1.7)	$27.3	($0.2)	$1.7	$0.3	($1.5)	$25.8	3,645	307
Line	$110.1	($174.8)	$12.9	$297.8	$4.0	$23.3	$0.7	($18.6)	$279.2	117,470	8,911
Transformer	$20.5	($28.0)	$6.7	$55.2	$1.8	($0.5)	($2.0)	$0.3	$55.5	70,393	2,022
Other	$5.0	($2.8)	$0.7	$8.4	$0.4	$0.7	$0.7	$0.4	$8.8	13,062	482
Unclassified	$0.1	($0.0)	$0.0	$0.1	($0.0)	$0.1	$0.1	($0.1)	$0.0	NA	NA
Total	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$455.4	224,543	16,473

Table 11-21 and Table 11-22 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 11-21. In the first nine months of 2018, there were 105,437 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 7,789 (7.4 percent) were also constrained in the Real-Time Energy Market. There were 60,917 congestion event hours in the Day-Ahead Energy Market for the period February 22, 2018 through September 30, 2018. Of those day-ahead congestion event hours, only 5,443 (8.9 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2017, of the 224,543 day-ahead congestion event hours, only 8,627 (3.8 percent) were binding in the Real-Time Energy Market.[22]

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 11-22. In the first nine months of 2018, of the 16,924 congestion event hours in the Real-Time Energy Market, 7,878 (46.5 percent) were also constrained in the Day-Ahead Energy Market. In the first nine months of 2017, of the 16,473 real-time congestion event hours, 8,378 (50.9 percent) were also in the Day-Ahead Energy Market.

Table 11-21 Congestion event hours (day-ahead against real-time): January through September, 2017 and 2018

	Congestion Event Hours					
	2017 (Jan - Sep)			2018 (Jan - Sep)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	19,973	1,942	9.7%	15,659	1,707	10.9%
Interface	3,645	186	5.1%	2,171	239	11.0%
Line	117,470	5,453	4.6%	60,750	5,024	8.3%
Transformer	70,393	775	1.1%	23,484	585	2.5%
Other	13,062	271	2.1%	3,373	234	6.9%
Total	224,543	8,627	3.8%	105,437	7,789	7.4%

22 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-22 Congestion event hours (real-time against day-ahead): January through September, 2017 and 2018

	Congestion Event Hours					
	2017 (Jan - Sep)			2018 (Jan - Sep)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	4,751	1,953	41.1%	4,240	1,709	40.3%
Interface	307	221	72.0%	391	264	67.5%
Line	8,911	5,210	58.5%	10,376	5,080	49.0%
Transformer	2,022	723	35.8%	1,344	591	44.0%
Other	482	271	56.2%	573	234	40.8%
Total	16,473	8,378	50.9%	16,924	7,878	46.5%

Table 11-23 shows congestion costs by facility voltage class for the first nine months of 2018. Congestion costs in the first nine months of 2018 increased for all facilities compared to the first nine months of 2017, caused by large increase in day-ahead congestion costs in January, 2018 (Table 11-24).

Table 11-23 Congestion summary (By facility voltage): January through September, 2018

	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	($1.3)	$0.1	$2.1	$0.7	$0.3	($0.0)	$0.4	$2.4	94	21
500	$85.5	($182.3)	($13.5)	$254.3	$16.7	$21.2	$11.4	$6.8	$261.1	3,708	955
345	$16.4	($242.9)	($1.9)	$257.4	$0.3	($1.8)	($8.7)	($6.6)	$250.8	17,616	2,244
230	$145.5	($50.2)	$4.3	$200.0	($2.0)	$5.5	($2.1)	($9.6)	$190.3	18,259	4,436
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$0.9	($4.2)	($0.3)	$4.8	$0.2	($0.4)	$0.4	$1.0	$5.8	218	55
138	($28.4)	($396.2)	($17.9)	$349.8	$2.6	$21.6	($3.6)	($22.6)	$327.2	40,091	6,961
115	$8.2	($54.9)	($3.0)	$60.0	($0.0)	$3.3	($1.1)	($4.4)	$55.6	11,895	1,553
69	$20.2	$0.8	$2.6	$21.9	($0.7)	($0.1)	($1.0)	($1.6)	$20.4	10,810	638
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.1	$0.0	($0.0)	$0.3	1,878	61
18	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	309	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
13	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	160	0
12	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	301	0
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.5	$0.4	$1.2	$1.2	$1.5	NA	NA
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$1,116.2	105,437	16,924

Table 11-24 Congestion summary (By facility voltage): January through September, 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	$0.5	($1.0)	$0.7	$2.3	($0.2)	$0.0	$0.0	($0.2)	$2.0	989	35
500	$54.1	($15.8)	($1.3)	$68.6	$1.5	$2.9	$3.7	$2.4	$70.9	6,585	1,098
345	($10.5)	($93.3)	$3.6	$86.4	$6.7	$6.5	($8.9)	($8.6)	$77.8	44,602	2,608
230	$75.8	($27.5)	$0.7	$103.9	$3.6	$9.5	$2.1	($3.8)	$100.1	34,485	3,909
161	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	8	17
138	($17.1)	($206.7)	($1.5)	$188.1	$3.8	$14.6	($6.9)	($17.7)	$170.4	98,648	6,845
115	($1.2)	($29.2)	($0.3)	$27.7	($0.4)	$3.1	$2.7	($0.8)	$26.9	23,194	1,434
69	$3.3	($1.5)	$0.2	$5.0	($2.6)	($3.8)	$0.3	$1.6	$6.6	11,377	527
34	$0.2	$0.0	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3,448	0
18	($0.0)	($0.1)	$0.1	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	1,160	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	36	0
Unclassified	$0.1	($0.0)	$0.0	$0.1	($0.0)	$0.1	$0.1	($0.1)	$0.0	NA	NA
Total	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$455.4	224,543	16,473

Constraint Duration

Table 11-25 lists the constraints for January through September, 2017 and 2018 that were most frequently binding and Table 11-26 shows the constraints which experienced the largest change in congestion event hours from the first nine months of 2017 to the first nine months of 2018. In Table 11-25, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first nine months of 2018. In Table 11-26, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first nine months of 2017 to the first nine months of 2018.

Table 11-25 Top 25 constraints with frequent occurrence: January through September, 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)			Day-Ahead (Jan - Sep)			Real-Time (Jan - Sep)		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Graceton - Safe Harbor	Line	2,795	2,986	191	1,021	1,805	784	43%	46%	3%	16%	28%	12%
2	Easton - Emuni	Line	1,502	2,734	1,232	1	2	1	23%	42%	19%	0%	0%	0%
3	Gardners - Texas East	Line	934	2,258	1,324	9	341	332	14%	34%	20%	0%	5%	5%
4	Quad Cities	Transformer	7,015	2,414	(4,601)	0	0	0	107%	37%	(70%)	0%	0%	0%
5	Monroe - Vineland	Line	203	1,692	1,489	13	94	81	3%	26%	23%	0%	1%	1%
6	Lakeview - Greenfield	Line	1,398	1,337	(61)	133	339	206	21%	20%	(1%)	2%	5%	3%
7	Emilie - Falls	Line	4,600	1,321	(3,279)	780	242	(538)	70%	20%	(50%)	12%	4%	(8%)
8	Newton	Flowgate	514	1,116	602	173	389	216	8%	17%	9%	3%	6%	3%
9	Brokaw - Leroy	Flowgate	803	1,232	429	317	261	(56)	12%	19%	7%	5%	4%	(1%)
10	Cedar Grove Sub - Roseland	Line	53	1,328	1,275	3	64	61	1%	20%	19%	0%	1%	1%
11	Conastone - Peach Bottom	Line	2,717	997	(1,720)	810	393	(417)	41%	15%	(26%)	12%	6%	(6%)
12	Tanners Creek - Miami Fort	Flowgate	0	1,346	1,346	0	0	0	0%	21%	21%	0%	0%	0%
13	Olive	Other	5,271	1,327	(3,944)	0	0	0	80%	20%	(60%)	0%	0%	0%
14	Flint Lake - Luchtman Road	Flowgate	0	890	890	0	365	365	0%	14%	14%	0%	6%	6%
15	Zion	Line	3,346	1,193	(2,153)	0	0	0	51%	18%	(33%)	0%	0%	0%
16	Roxana - Praxair	Flowgate	1,315	769	(546)	268	405	137	20%	12%	(8%)	4%	6%	2%
17	Waukegan	Transformer	3,973	1,083	(2,890)	0	0	0	61%	17%	(44%)	0%	0%	0%
18	Pleasant Prairie - Zion	Flowgate	1,555	1,011	(544)	278	60	(218)	24%	15%	(8%)	4%	1%	(3%)
19	Quad Cities - Cordova	Flowgate	134	1,035	901	0	0	0	2%	16%	14%	0%	0%	0%
20	Cedar Creek - Red Lion	Line	673	918	245	34	69	35	10%	14%	4%	1%	1%	1%
21	Person - Sedge Hill	Line	58	814	756	25	136	111	1%	12%	12%	0%	2%	2%
22	Canton - South Troy	Line	138	949	811	0	0	0	2%	14%	12%	0%	0%	0%
23	Monroe - Lallendorf	Flowgate	37	945	908	0	0	0	1%	14%	14%	0%	0%	0%
24	Tanners Creek - Miami Fort	Line	460	509	49	12	435	423	7%	8%	1%	0%	7%	6%
25	Maple - Jackson	Line	134	775	641	2	135	133	2%	12%	10%	0%	2%	2%

Table 11-26 Top 25 constraints with largest year to year change in occurrence: January through September, 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)			(Jan - Sep)		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Quad Cities	Transformer	7,015	2,414	(4,601)	0	0	0	107%	37%	(70%)	0%	0%	0%
2	Olive	Other	5,271	1,327	(3,944)	0	0	0	80%	20%	(60%)	0%	0%	0%
3	Emilie - Falls	Line	4,600	1,321	(3,279)	780	242	(538)	70%	20%	(50%)	12%	4%	(8%)
4	Westwood	Flowgate	3,145	0	(3,145)	198	0	(198)	48%	0%	(48%)	3%	0%	(3%)
5	Braidwood - East Frankfort	Line	3,241	157	(3,084)	248	86	(162)	49%	2%	(47%)	4%	1%	(2%)
6	Hinchmans	Transformer	3,725	773	(2,952)	0	0	0	57%	12%	(45%)	0%	0%	0%
7	Howard - Shelby	Line	2,905	0	(2,905)	0	0	0	44%	0%	(44%)	0%	0%	0%
8	Waukegan	Transformer	3,973	1,083	(2,890)	0	0	0	61%	17%	(44%)	0%	0%	0%
9	Loretto - Vienna	Line	3,404	772	(2,632)	60	4	(56)	52%	12%	(40%)	1%	0%	(1%)
10	East Bend	Transformer	2,977	453	(2,524)	0	0	0	45%	7%	(39%)	0%	0%	0%
11	Seneca	Transformer	2,531	299	(2,232)	0	0	0	39%	5%	(34%)	0%	0%	0%
12	Elwood	Other	2,213	0	(2,213)	0	0	0	34%	0%	(34%)	0%	0%	0%
13	Tanners Creek	Transformer	2,585	402	(2,183)	0	0	0	39%	6%	(33%)	0%	0%	0%
14	Zion	Line	3,346	1,193	(2,153)	0	0	0	51%	18%	(33%)	0%	0%	0%
15	Conastone - Peach Bottom	Line	2,717	997	(1,720)	810	393	(417)	41%	15%	(26%)	12%	6%	(6%)
16	Liquid Carbonics	Transformer	2,214	147	(2,067)	0	0	0	34%	2%	(32%)	0%	0%	0%
17	Gould Street - Westport	Line	2,423	417	(2,006)	0	8	8	37%	6%	(31%)	0%	0%	0%
18	West Chicago	Transformer	2,517	606	(1,911)	0	0	0	38%	9%	(29%)	0%	0%	0%
19	Cherry Valley	Transformer	2,142	325	(1,817)	92	1	(91)	33%	5%	(28%)	1%	0%	(1%)
20	Essex Co. RRF	Transformer	2,338	430	(1,908)	0	0	0	36%	7%	(29%)	0%	0%	0%
21	Saddlebrook	Transformer	2,201	322	(1,879)	0	0	0	34%	5%	(29%)	0%	0%	0%
22	West Moulton - City Of St. Marys	Line	2,248	399	(1,849)	0	0	0	34%	6%	(28%)	0%	0%	0%
23	Beryl - Westvaco	Line	2,038	310	(1,728)	0	0	0	31%	5%	(26%)	0%	0%	0%
24	Linden - North Ave	Line	1,705	14	(1,691)	30	0	(30)	26%	0%	(26%)	0%	0%	(0%)
25	Iogtown - North Delphos	Line	1,876	174	(1,702)	0	0	0	29%	3%	(26%)	0%	0%	0%

Constraint Costs

Table 11-27 and Table 11-28 show the top constraints affecting congestion costs by facility for the first nine months of 2018 and 2017. The AEP – DOM Interface was the largest contributor to congestion costs in the first nine months of 2018, with $120.4 million in total congestion costs and 10.8 percent of the total PJM congestion costs in the first nine months of 2018.

Table 11-27 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2018[23]

				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	2018 (Jan - Sep)
1	AEP - DOM	Interface	500	$55.2	($66.6)	($5.2)	$116.6	$13.4	$18.7	$9.0	$3.8	$120.4	10.8%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.5	$3.7	$1.6	$87.6	7.9%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($19.7)	($90.0)	($2.9)	$67.3	$0.0	$0.0	$0.0	$0.0	$67.3	6.0%
4	Graceton - Safe Harbor	Line	BGE	$87.3	$29.2	$2.3	$60.4	$0.0	$4.5	($1.5)	($5.9)	$54.5	4.9%
5	5004/5005 Interface	Interface	500	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	3.2%
6	Batesville - Hubble	Flowgate	MISO	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.4	$2.0	$34.5	3.1%
7	Conastone - Peach Bottom	Line	500	$27.0	$0.7	($0.2)	$26.1	$1.6	$0.7	($0.1)	$0.7	$26.8	2.4%
8	Lakeview - Greenfield	Line	ATSI	($20.2)	($56.7)	($1.6)	$34.9	($1.4)	$8.9	$0.3	($10.1)	$24.8	2.2%
9	Bedington - Black Oak	Interface	500	$10.0	($13.9)	($1.4)	$22.5	$0.6	$0.7	$0.6	$0.5	$23.0	2.1%
10	AP South	Interface	500	$13.7	($8.1)	($1.5)	$20.2	$0.0	$0.1	($0.0)	($0.1)	$20.1	1.8%
11	Capitol Hill - Chemical	Line	AEP	$12.3	($5.0)	$0.5	$17.9	$0.8	($0.8)	($0.0)	$1.6	$19.4	1.7%
12	Gardners - Texas East	Line	Met-Ed	($5.4)	($21.5)	($0.1)	$16.0	$0.1	($0.2)	$0.4	$0.7	$16.7	1.5%
13	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.4%
14	Cedar Creek - Red Lion	Line	DPL	$2.4	($12.1)	$0.8	$15.3	($0.8)	($1.8)	($0.6)	$0.4	$15.7	1.4%
15	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.3%
16	Maple - Jackson	Line	ATSI	($10.4)	($23.6)	$1.5	$14.7	$0.4	$0.7	($0.9)	($1.3)	$13.5	1.2%
17	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.2%
18	Nottingham	Other	PECO	$12.8	$0.5	$0.4	$12.8	$0.0	$0.0	$0.0	$0.0	$12.8	1.1%
19	Conastone - Northwest	Line	BGE	$9.5	($1.0)	($0.7)	$9.8	($1.0)	($0.7)	$1.1	$0.8	$10.6	0.9%
20	Emilie - Falls	Line	PECO	$3.0	($6.7)	$0.3	$10.0	$0.3	$0.4	$0.4	$0.2	$10.2	0.9%
21	Monroe - Lallendorf	Flowgate	MISO	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	0.9%
22	Flint Lake - Luchtman Road	Flowgate	MISO	$0.2	($10.6)	($4.9)	$5.8	($0.2)	($1.4)	$1.7	$2.9	$8.7	0.8%
23	Krendale - Shanorma	Line	APS	($5.6)	($13.8)	$0.6	$8.7	$0.0	$0.0	$0.0	$0.0	$8.7	0.8%
24	Bagley - Graceton	Line	BGE	$7.5	($0.8)	$0.4	$8.7	$0.7	$1.0	($0.2)	($0.4)	$8.3	0.7%
25	Tanners Creek - Miami Fort	Line	AEP	($2.2)	($10.0)	($0.4)	$7.4	($1.2)	($2.3)	($0.7)	$0.4	$7.8	0.7%

23 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September, 2017[24]

				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 (Jan - Sep)
1	Braidwood - East Frankfort	Line	ComEd	($3.1)	($38.6)	($0.0)	$35.5	$0.7	$2.0	($0.6)	($1.9)	$33.6	7.4%
2	Conastone - Peach Bottom	Line	500	$33.2	$2.0	$0.1	$31.4	$1.6	$1.2	$1.6	$2.0	$33.4	7.3%
3	Emilie - Falls	Line	PECO	$10.2	($11.9)	$0.2	$22.3	$0.2	$1.2	$0.5	($0.5)	$21.8	4.8%
4	Graceton - Safe Harbor	Line	BGE	$25.6	$5.8	$0.1	$19.9	$1.3	$2.1	$1.3	$0.5	$20.4	4.5%
5	Westwood	Flowgate	MISO	($21.5)	($38.8)	$0.6	$17.9	$1.2	$0.8	($0.5)	($0.1)	$17.8	3.9%
6	AP South	Interface	500	$9.8	($4.6)	($1.3)	$13.1	($0.0)	$1.3	$0.9	($0.5)	$12.6	2.8%
7	Cherry Valley	Transformer	ComEd	$4.6	($7.1)	$1.3	$12.9	($0.2)	$0.8	$0.3	($0.7)	$12.2	2.7%
8	Conastone - Northwest	Line	BGE	$10.1	($0.9)	($0.4)	$10.6	$0.1	$0.5	$0.9	$0.5	$11.1	2.4%
9	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	2.4%
10	Three Mile Island	Transformer	500	$5.7	($3.8)	($0.3)	$9.3	($0.0)	($0.4)	$0.9	$1.3	$10.5	2.3%
11	Lake George - Aetna	Flowgate	MISO	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.9	$2.7	$9.1	2.0%
12	Lakeview - Greenfield	Line	ATSI	($2.3)	($10.8)	$0.4	$8.9	($0.1)	$0.3	$0.1	($0.3)	$8.6	1.9%
13	Bedington - Black Oak	Interface	500	$4.1	($2.8)	($0.0)	$6.9	$0.0	$0.2	$0.4	$0.2	$7.1	1.6%
14	Butler - Shanor Manor	Line	APS	($6.5)	($13.0)	$0.8	$7.2	$1.6	$1.6	($0.4)	($0.4)	$6.8	1.5%
15	Pleasant View - Ashburn	Line	Dominion	$5.6	($3.5)	($0.3)	$8.7	($1.1)	$1.0	($0.1)	($2.3)	$6.5	1.4%
16	Loretto - Vienna	Line	DPL	$7.6	$1.9	$0.5	$6.1	($0.4)	$0.1	$0.2	($0.3)	$5.8	1.3%
17	Greentown	Flowgate	MISO	($1.4)	($7.6)	($0.7)	$5.6	($0.9)	($0.5)	$0.4	$0.0	$5.6	1.2%
18	Batesville - Hubble	Flowgate	MISO	($4.2)	($14.0)	($3.0)	$6.8	($0.1)	($1.1)	($2.4)	($1.3)	$5.4	1.2%
19	Bagley - Graceton	Line	BGE	$4.6	($0.4)	($0.0)	$5.0	$0.2	$0.4	$0.1	($0.1)	$4.9	1.1%
20	Brunner Island - Yorkanna	Line	Met-Ed	$3.5	($1.2)	($0.1)	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1.0%
21	Byron - Cherry Valley	Flowgate	MISO	($0.7)	($5.4)	($0.1)	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1.0%
22	Quarry - Steel City	Line	PPL	($0.1)	($4.3)	($0.1)	$4.2	$0.0	$0.0	$0.3	$0.3	$4.4	1.0%
23	Middletown Jct - Brunner Island	Line	PPL	$1.9	($2.5)	($0.2)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	0.9%
24	Havana E - Havana S	Flowgate	MISO	($2.0)	($6.3)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	0.9%
25	Quad Cities	Transformer	ComEd	($1.3)	($4.7)	$0.6	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	0.9%

24 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless the location of the flowgates.

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 the first nine months of 2018. 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 the first nine months of 2018. 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 the first nine months of 2018.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: January through September, 2018

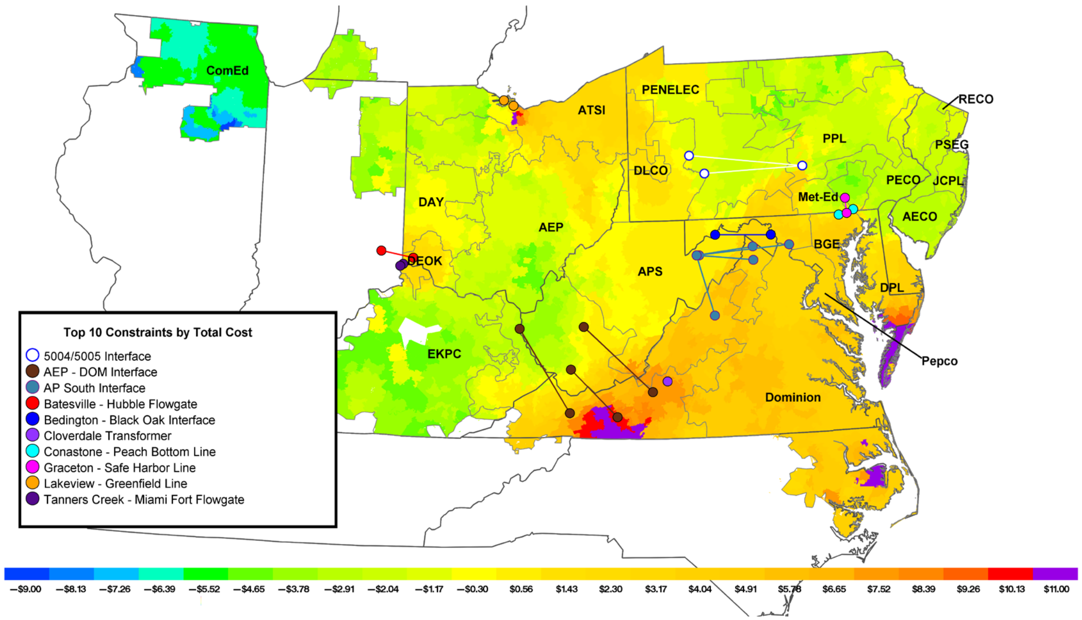


Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: January through September, 2018

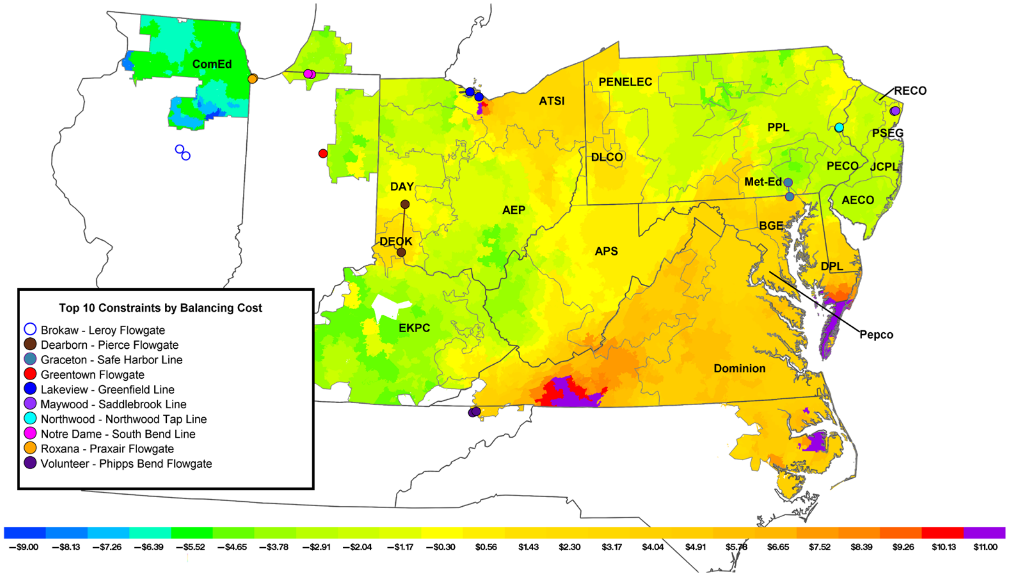
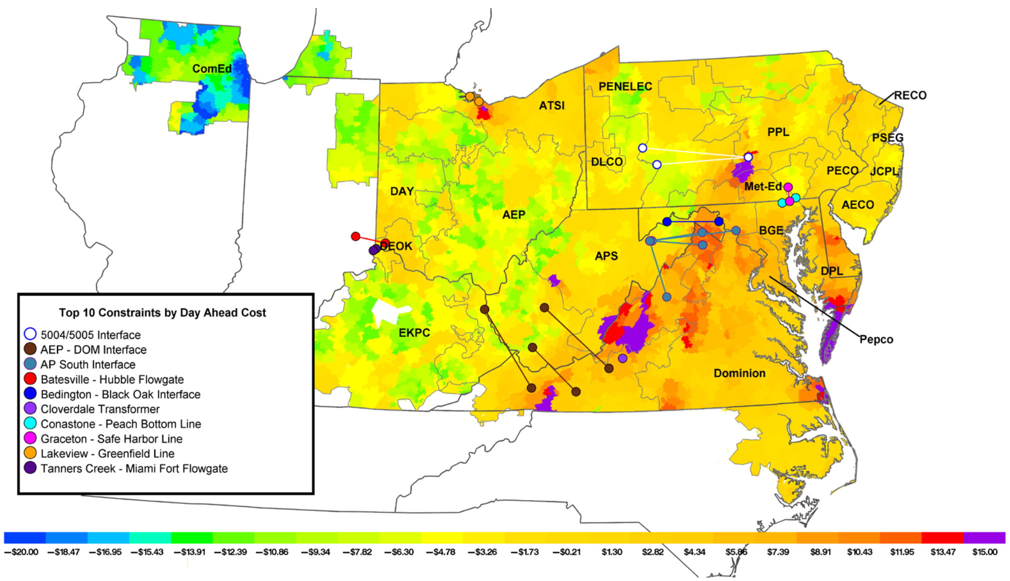


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: January through September, 2018



Constraint Specific Contribution to Area Based and Constraint Based Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM West Region with eight control zones (the AP, ATSI, ComEd, AEP, DLCO, DEOK, DAY and EKPC control zones); and the PJM South Region with one control zone (the Dominion Control Zone).[25]

Table 11-29 through Table 11-48 present the congestion costs of the top 20 constraints affecting each control zone using both area based calculations and constraint based calculations, including the facility type, the location of the constrained facility, day-ahead event hours and real-time event hours for the first nine months of 2018. The tables present the top 20 constraints in descending order of the absolute value of congestion costs for each zone using constraint based calculations. In addition to the top 20 constraints, these tables show the congestion costs of all other constraints affecting the control zone.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 11-29 AECO Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Monroe - Vineland	Line	AECO	$1.9	($0.1)	$1.8	$1.7	$0.0	$1.7	1,692	94
2	5004/5005 Interface	Interface	500	$1.7	$0.2	$1.9	$1.4	$0.1	$1.5	174	47
3	Cloverdale	Transformer	AEP	$0.8	$0.2	$1.0	$1.1	$0.0	$1.2	615	99
4	AEP - DOM	Interface	500	$0.3	$0.0	$0.3	$0.4	$0.0	$0.5	664	150
5	Lakeview - Greenfield	Line	ATSI	$0.5	$0.1	$0.6	$0.4	$0.0	$0.5	1,337	339
6	Graceton - Safe Harbor	Line	BGE	($2.7)	($1.5)	($4.2)	$0.0	($0.3)	($0.3)	2,986	1,805
7	Chambers	Transformer	AECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	0	0
8	Bedington - Black Oak	Interface	500	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	307	52
9	East	Interface	500	$0.2	$0.0	$0.3	$0.2	$0.0	$0.2	106	2
10	Maywood - Saddlebrook	Line	PSEG	($0.1)	($0.1)	($0.1)	$0.0	($0.2)	($0.2)	378	98
11	Riverside	Line	BGE	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	265	69
12	Person - Sedge Hill	Line	Dominion	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	814	136
13	East Townada - North Meshoppen	Line	PENELEC	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	605	0
14	North Meshoppen - Oxbow	Line	PENELEC	$0.1	$0.0	$0.2	$0.1	$0.1	$0.2	487	164
15	Brokaw - Leroy	Flowgate	MISO	$0.1	($0.0)	$0.1	$0.1	$0.1	$0.2	1,232	261
16	West	Interface	500	$0.2	($0.0)	$0.2	$0.2	$0.0	$0.2	66	11
17	Flint Lake - Luchtman Road	Flowgate	MISO	$0.2	$0.0	$0.2	$0.1	$0.1	$0.1	890	365
18	AP South	Interface	500	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	447	31
19	Tiltonsville - Windsor	Line	APS	$0.1	($0.0)	$0.1	$0.1	$0.0	$0.1	355	9
20	Keeney - Rockspring	Line	500	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	158	0
	Top 20 Total			$4.4	($1.0)	$3.4	$7.3	($0.2)	$7.1	13,578	3,732
	All Other Constraints			($5.5)	($1.5)	($7.0)	$2.3	($0.4)	$1.9	58,648	12,717
	Total			($1.1)	($2.4)	($3.5)	$9.6	($0.6)	$9.0	72,226	16,449

25 See "Operating Agreement of PJM Interconnection, L.L.C.," (June 1, 2017) Section OA 1. DEFINITIONS <http://www.pjm.com/documents/agreements.aspx>.

BGE Control Zone

Table 11-30 BGE Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Graceton - Safe Harbor	Line	BGE	$17.7	($1.3)	$16.5	$11.9	$0.4	$12.3	2,986	1,805
2	Cloverdale	Transformer	AEP	$1.2	$0.6	$1.7	$6.9	$0.3	$7.2	615	99
3	AEP - DOM	Interface	500	$0.4	$0.6	$1.0	$5.6	$0.5	$6.2	664	150
4	Riverside	Line	BGE	$8.2	($0.3)	$7.9	$4.7	$0.1	$4.8	265	69
5	Conastone - Peach Bottom	Line	500	$4.7	($0.7)	$4.0	$3.5	$0.2	$3.7	997	393
6	Bedington - Black Oak	Interface	500	$0.8	$0.2	$1.0	$3.2	$0.1	$3.3	307	52
7	Bagley - Graceton	Line	BGE	$2.9	($0.0)	$2.9	$2.3	$0.1	$2.4	458	182
8	AP South	Interface	500	$0.7	($0.0)	$0.7	$2.3	$0.0	$2.3	447	31
9	Conastone - Northwest	Line	BGE	$3.3	($0.7)	$2.7	$2.0	$0.2	$2.2	234	156
10	5004/5005 Interface	Interface	500	$1.6	$0.3	$2.0	$2.0	$0.1	$2.1	174	47
11	Nottingham	Other	PECO	$1.8	$0.0	$1.8	$1.8	$0.0	$1.8	606	295
12	Face Rock	Other	PPL	$1.6	$0.0	$1.6	$1.3	$0.0	$1.3	541	0
13	Person - Sedge Hill	Line	Dominion	$0.7	$0.0	$0.7	$1.2	$0.0	$1.3	814	136
14	Lakeview - Greenfield	Line	ATSI	$1.4	$0.3	$1.7	$1.1	$0.1	$1.1	1,337	339
15	BCPEP	Interface	Pepco	$0.8	$0.0	$0.8	$1.0	$0.0	$1.0	116	0
16	Howard - Pumphrey	Line	Pepco	$0.8	$0.0	$0.8	$0.6	$0.0	$0.6	74	0
17	Center - Westport	Line	BGE	$1.5	($0.0)	$1.5	$0.6	$0.0	$0.6	112	20
18	Brokaw - Leroy	Flowgate	MISO	$0.4	$0.0	$0.5	$0.4	$0.2	$0.6	1,232	261
19	Face Rock	Transformer	PPL	$0.5	$0.0	$0.5	$0.6	$0.0	$0.6	268	0
20	Brandon Shores - Riverside	Line	BGE	$2.8	($0.3)	$2.6	$0.5	($0.0)	$0.5	89	38
	Top 20 Total			$53.8	($1.2)	$52.5	$53.7	$2.2	$55.9	12,336	4,073
	All Other Constraints			($1.8)	$0.6	($1.2)	$8.2	($0.5)	$7.7	58,459	12,317
	Total			$52.0	($0.7)	$51.3	$61.9	$1.7	$63.6	70,795	16,390

DPL Control Zone

Table 11-31 DPL Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Cedar Creek - Red Lion	Line	DPL	$13.8	$0.6	$14.4	$15.3	$0.6	$15.9	918	69
2	Loretto - Vienna	Line	DPL	$5.1	$0.1	$5.3	$5.2	$0.1	$5.3	772	4
3	Cedar Creek - Clayton	Line	DPL	$4.7	$0.1	$4.8	$4.8	$0.2	$5.1	684	29
4	North Salisbury - Rockawalkin	Line	DPL	$4.3	$0.0	$4.3	$4.4	$0.0	$4.4	637	0
5	5004/5005 Interface	Interface	500	$5.9	($0.4)	$5.5	$3.4	$0.1	$3.5	174	47
6	Coolspring - Milford	Line	DPL	$2.6	$0.3	$2.9	$2.7	$0.4	$3.1	86	7
7	Cloverdale	Transformer	AEP	$3.6	($1.0)	$2.6	$2.8	$0.1	$2.9	615	99
8	Preston - Tanyard	Line	DPL	$2.5	$0.0	$2.6	$2.6	$0.0	$2.6	586	11
9	North Salisbury - Pemberton	Line	DPL	$2.2	($0.3)	$1.9	$2.2	$0.0	$2.3	469	109
10	Kent - Vaughn	Line	DPL	$1.4	($0.0)	$1.4	$1.4	$0.0	$1.4	307	16
11	AEP - DOM	Interface	500	$1.2	($0.5)	$0.7	$1.1	$0.1	$1.2	664	150
12	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.5	$1.0	$0.0	$1.1	1,337	339
13	Easton	Transformer	DPL	$0.9	$0.0	$0.9	$0.9	$0.1	$0.9	101	14
14	Milford - Steele	Line	DPL	$0.7	$0.0	$0.7	$0.8	$0.0	$0.8	50	10
15	Bedington - Black Oak	Interface	500	$0.9	($0.1)	$0.8	$0.7	$0.0	$0.7	307	52
16	Easton - Emuni	Line	DPL	$0.7	($0.0)	$0.6	$0.7	($0.0)	$0.7	2,734	2
17	Keeney - Rockspring	Line	500	$0.9	$0.0	$0.9	$0.6	$0.0	$0.6	158	0
18	Mardela - Vienna	Line	DPL	$0.6	$0.0	$0.6	$0.6	$0.0	$0.6	478	0
19	Graceton - Safe Harbor	Line	BGE	($12.2)	$2.7	($9.5)	$0.0	($0.6)	($0.6)	2,986	1,805
20	East	Interface	500	$0.7	($0.0)	$0.7	$0.6	$0.0	$0.6	106	2
	Top 20 Total			$42.7	$0.9	$43.6	$51.8	$1.3	$53.1	14,169	2,765
	All Other Constraints			($11.1)	$2.1	($8.9)	$9.8	($0.1)	$9.7	58,102	13,684
	Total			$31.6	$3.0	$34.6	$61.6	$1.2	$62.8	72,271	16,449

JCPL Control Zone

Table 11-32 JCPL Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	5004/5005 Interface	Interface	500	$6.8	($1.3)	$5.4	$3.4	$0.1	$3.6	174	47
2	Emilie - Falls	Line	PECO	$1.2	$0.2	$1.4	$2.5	$0.1	$2.6	1,321	242
3	Cloverdale	Transformer	AEP	$3.9	($1.2)	$2.8	$2.4	$0.1	$2.5	615	99
4	Northwood	Transformer	Met-Ed	$1.3	$0.1	$1.4	$2.0	$0.0	$2.0	64	15
5	Northwood - Northwood Tap	Line	Met-Ed	$1.0	($0.4)	$0.6	$1.7	$0.2	$1.9	56	72
6	AEP - DOM	Interface	500	$1.4	($0.2)	$1.3	$1.0	$0.1	$1.1	664	150
7	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.5	$1.0	$0.0	$1.0	1,337	339
8	Maywood - Saddlebrook	Line	PSEG	($0.2)	($0.2)	($0.4)	$0.0	($0.9)	($0.9)	378	98
9	Graceton - Safe Harbor	Line	BGE	($0.7)	($3.2)	($3.9)	$0.0	($0.8)	($0.8)	2,986	1,805
10	Wescosville	Transformer	PPL	$0.2	$0.1	$0.2	$0.3	$0.2	$0.6	104	52
11	East	Interface	500	$1.1	($0.0)	$1.1	$0.5	$0.0	$0.5	106	2
12	East Townada - North Meshoppen	Line	PENELEC	$0.8	$0.0	$0.8	$0.5	$0.0	$0.5	605	0
13	Bedington - Black Oak	Interface	500	$0.6	($0.1)	$0.5	$0.4	$0.0	$0.4	307	52
14	Person - Sedge Hill	Line	Dominion	$0.2	$0.1	$0.3	$0.4	$0.0	$0.4	814	136
15	North Meshoppen - Oxbow	Line	PENELEC	$0.7	($0.4)	$0.3	$0.2	$0.2	$0.4	487	164
16	Riverside	Line	BGE	$0.2	$0.1	$0.2	$0.4	$0.0	$0.4	265	69
17	West	Interface	500	$1.1	($0.1)	$1.0	$0.4	$0.0	$0.4	66	11
18	Brokaw - Leroy	Flowgate	MISO	$0.5	($0.0)	$0.5	$0.2	$0.1	$0.4	1,232	261
19	Flint Lake - Luchtman Road	Flowgate	MISO	($0.0)	$0.2	$0.1	$0.2	$0.1	$0.3	890	365
20	Tiltonsville - Windsor	Line	APS	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	355	9
	Top 20 Total			$22.4	($7.0)	$15.4	$17.9	($0.3)	$17.6	12,826	3,988
	All Other Constraints			$0.4	($6.6)	($6.2)	$5.2	($1.1)	$4.1	59,838	12,461
	Total			$22.9	($13.6)	$9.2	$23.0	($1.4)	$21.6	72,664	16,449

Met-Ed Control Zone

Table 11-33 Met-Ed Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Gardners - Texas East	Line	Met-Ed	$8.1	($0.1)	$8.0	$6.3	$0.2	$6.5	2,258	341
2	Middletown Jct	Transformer	Met-Ed	$3.7	$0.0	$3.7	$3.4	$0.0	$3.4	435	0
3	5004/5005 Interface	Interface	500	($0.3)	($0.5)	($0.8)	$2.4	$0.1	$2.5	174	47
4	Cloverdale	Transformer	AEP	$0.2	($0.6)	($0.4)	$2.0	$0.1	$2.1	615	99
5	Hunterstown	Transformer	500	$1.9	$0.0	$1.9	$1.9	$0.0	$1.9	8	0
6	Northwood	Transformer	Met-Ed	$1.1	($0.1)	$1.0	$1.8	$0.0	$1.8	64	15
7	Northwood - Northwood Tap	Line	Met-Ed	$0.8	($1.0)	($0.1)	$1.5	($0.3)	$1.2	56	72
8	Ironwood - South Lebanon	Line	Met-Ed	$1.0	($0.2)	$0.9	$1.0	($0.1)	$1.0	0	53
9	AEP - DOM	Interface	500	$0.2	($0.2)	($0.0)	$0.8	$0.1	$0.9	664	150
10	Lakeview - Greenfield	Line	ATSI	($0.2)	($0.5)	($0.6)	$0.8	$0.0	$0.9	1,337	339
11	Graceton - Safe Harbor	Line	BGE	$1.5	$0.8	$2.3	$0.0	($0.9)	($0.9)	2,986	1,805
12	Bedington - Black Oak	Interface	500	$0.1	($0.0)	$0.1	$0.5	$0.0	$0.5	307	52
13	Cly - ES3 Conewago	Line	Met-Ed	$0.4	$0.0	$0.4	$0.4	$0.0	$0.4	29	0
14	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.4	$0.0	$0.4	$0.4	$0.0	$0.4	298	0
15	Three Mile Island	Other	Met-Ed	$0.4	$0.0	$0.5	$0.3	$0.1	$0.4	62	17
16	East Waynesboro - Ringgold	Line	APS	$0.4	$0.0	$0.4	$0.4	$0.0	$0.4	49	0
17	Riverside	Line	BGE	$0.0	$0.0	$0.1	$0.3	$0.0	$0.3	265	69
18	Hunterstown	Transformer	Met-Ed	$0.2	($0.5)	($0.3)	$0.2	($0.5)	($0.3)	8	0
19	Person - Sedge Hill	Line	Dominion	($0.1)	$0.0	($0.1)	$0.3	$0.0	$0.3	814	136
20	North Meshoppen - Oxbow	Line	PENELEC	$0.1	($0.2)	($0.1)	$0.2	$0.1	$0.3	487	164
	Top 20 Total			$20.2	($2.9)	$17.2	$25.0	($0.9)	$24.0	10,916	3,359
	All Other Constraints			$7.7	($2.2)	$5.5	$5.3	($0.4)	$4.9	62,311	13,031
	Total			$27.8	($5.1)	$22.7	$30.3	($1.3)	$28.9	73,227	16,390

PECO Control Zone

Table 11-34 PECO Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	5004/5005 Interface	Interface	500	($3.5)	$0.1	($3.4)	$6.4	$0.2	$6.6	174	47
2	Cloverdale	Transformer	AEP	($3.2)	$1.5	($1.7)	$5.0	$0.2	$5.3	615	99
3	AEP - DOM	Interface	500	($1.0)	$0.6	($0.4)	$2.0	$0.2	$2.1	664	150
4	Lakeview - Greenfield	Line	ATSI	($2.6)	$0.5	($2.0)	$2.0	$0.1	$2.1	1,337	339
5	Plymouth Meeting - Whitpain	Line	PECO	$1.9	$0.2	$2.2	$1.6	$0.1	$1.8	178	15
6	Graceton - Safe Harbor	Line	BGE	$34.1	($0.3)	$33.8	$0.0	($1.3)	($1.3)	2,986	1,805
7	Bedington - Black Oak	Interface	500	($1.1)	$0.1	($1.0)	$1.1	$0.0	$1.1	307	52
8	East	Interface	500	$1.0	($0.0)	$1.0	$0.9	($0.0)	$0.9	106	2
9	Person - Sedge Hill	Line	Dominion	($1.1)	$0.0	($1.0)	$0.8	$0.0	$0.8	814	136
10	Riverside	Line	BGE	($0.4)	$0.1	($0.3)	$0.7	$0.0	$0.7	265	69
11	North Meshoppen - Oxbow	Line	PENELEC	($0.5)	$0.1	($0.4)	$0.4	$0.3	$0.7	487	164
12	East Townada - North Meshoppen	Line	PENELEC	($0.2)	$0.0	($0.2)	$0.7	$0.0	$0.7	605	0
13	Brokaw - Leroy	Flowgate	MISO	($0.8)	$0.1	($0.7)	$0.5	$0.2	$0.7	1,232	261
14	West	Interface	500	($1.1)	$0.1	($0.9)	$0.7	$0.0	$0.7	66	11
15	Peachbottom	Transformer	PECO	$1.2	$0.0	$1.2	$0.7	$0.0	$0.7	137	0
16	Maywood - Saddlebrook	Line	PSEG	$0.1	($0.1)	$0.0	$0.0	($0.7)	($0.7)	378	98
17	Flint Lake - Luchtman Road	Flowgate	MISO	($1.2)	$0.0	($1.2)	$0.3	$0.3	$0.6	890	365
18	AP South	Interface	500	($0.7)	($0.0)	($0.7)	$0.5	$0.0	$0.5	447	31
19	Northport - Albion	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.4	$0.1	$0.5	132	28
20	Tiltonsville - Windsor	Line	APS	($0.4)	$0.0	($0.4)	$0.4	$0.0	$0.5	355	9
	Top 20 Total			$20.2	$3.2	$23.4	$25.1	($0.1)	$25.0	12,175	3,681
	All Other Constraints			$61.4	($2.5)	$58.9	$9.8	($1.7)	$8.1	59,597	12,768
	Total			$81.6	$0.7	$82.3	$34.8	($1.7)	$33.1	71,772	16,449

PENELEC Control Zone

Table 11-35 PENELEC Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Gardners - Texas East	Line	Met-Ed	$3.6	($0.2)	$3.4	$3.2	$0.1	$3.3	2,258	341
2	Lakeview - Greenfield	Line	ATSI	($5.4)	($0.3)	($5.7)	$2.1	$0.1	$2.2	1,337	339
3	Titusville - Union City	Line	PENELEC	$1.9	$0.1	$2.0	$1.9	$0.1	$2.0	251	76
4	Edgewood - Shelocta	Line	PENELEC	$0.6	$0.6	$1.3	$0.6	$0.5	$1.2	195	17
5	Butler - Karns City	Line	APS	$1.1	$0.1	$1.2	$1.0	$0.1	$1.1	152	15
6	Cloverdale	Transformer	AEP	($3.0)	($0.1)	($3.0)	$0.8	$0.0	$0.8	615	99
7	Asylum	Transformer	PENELEC	$0.7	$0.0	$0.7	$0.7	$0.0	$0.7	146	0
8	Dixonville - Glory	Line	PENELEC	$0.9	$0.0	$0.9	$0.7	$0.0	$0.7	25	0
9	East Townada - North Meshoppen	Line	PENELEC	$5.5	$0.0	$5.5	$0.6	$0.0	$0.6	605	0
10	Keystone - Shelocta	Line	PENELEC	$0.3	$0.2	$0.5	$0.3	$0.1	$0.4	6	5
11	5004/5005 Interface	Interface	500	$10.8	$0.5	$11.3	$0.4	$0.0	$0.4	174	47
12	New Comerstown - South Coshoct	Line	AEP	($0.5)	$0.1	($0.4)	$0.3	$0.0	$0.3	266	44
13	Burma - Piney Creek	Line	APS	$0.5	$0.0	$0.5	$0.3	$0.0	$0.3	19	0
14	Carlisle Pike - Gardners	Line	PENELEC	$0.3	($0.0)	$0.3	$0.3	$0.0	$0.3	251	2
15	Brokaw - Leroy	Flowgate	MISO	($1.2)	($0.0)	($1.2)	$0.2	$0.1	$0.3	1,232	261
16	Canton - South Troy	Line	PENELEC	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	949	0
17	Flint Lake - Luchtman Road	Flowgate	MISO	($1.5)	$0.0	($1.5)	$0.1	$0.1	$0.3	890	365
18	Graceton - Safe Harbor	Line	BGE	$9.1	($0.5)	$8.7	$0.0	($0.3)	($0.3)	2,986	1,805
19	Cedar Grove Sub - Roseland	Line	PSEG	($0.2)	$0.0	($0.2)	$0.2	$0.0	$0.2	1,328	64
20	East Waynesboro - Ringgold	Line	APS	$0.4	$0.0	$0.4	$0.2	$0.0	$0.2	49	0
	Top 20 Total			$24.3	$0.5	$24.8	$14.5	$1.0	$15.4	13,734	3,480
	All Other Constraints			$37.3	($4.5)	$32.9	$6.9	($0.3)	$6.6	60,900	12,910
	Total			$61.6	($4.0)	$57.6	$21.3	$0.7	$22.0	74,634	16,390

Pepco Control Zone

Table 11-36 Pepco Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Graceton - Safe Harbor	Line	BGE	$13.8	$1.1	$14.9	$8.5	$0.2	$8.8	2,986	1,805
2	AEP - DOM	Interface	500	$5.0	($0.6)	$4.4	$7.3	$0.6	$8.0	664	150
3	Cloverdale	Transformer	AEP	$5.9	$0.6	$6.5	$7.6	$0.3	$7.9	615	99
4	Bedington - Black Oak	Interface	500	$2.9	$0.1	$3.0	$3.7	$0.1	$3.8	307	52
5	Conastone - Peach Bottom	Line	500	$5.0	$0.2	$5.2	$3.3	$0.1	$3.4	997	393
6	AP South	Interface	500	$2.1	$0.0	$2.1	$2.9	$0.0	$2.9	447	31
7	Conastone - Northwest	Line	BGE	$1.4	$0.3	$1.8	$1.5	$0.2	$1.7	234	156
8	Person - Sedge Hill	Line	Dominion	$1.4	($0.0)	$1.3	$1.5	$0.1	$1.5	814	136
9	Nottingham	Other	PECO	$2.0	$0.0	$2.0	$1.4	$0.0	$1.4	606	295
10	Bagley - Graceton	Line	BGE	$1.4	$0.1	$1.5	$1.2	$0.0	$1.3	458	182
11	BCPEP	Interface	Pepco	$1.0	$0.0	$1.0	$1.0	$0.0	$1.0	116	0
12	5004/5005 Interface	Interface	500	$0.9	$0.1	$1.0	$0.8	$0.0	$0.9	174	47
13	Face Rock	Other	PPL	$0.5	$0.0	$0.5	$0.7	$0.0	$0.7	541	0
14	Lincoln - Straban	Line	PENELEC	$1.1	($0.0)	$1.0	$0.6	$0.0	$0.6	603	189
15	Brokaw - Leroy	Flowgate	MISO	$0.8	($0.0)	$0.7	$0.4	$0.2	$0.6	1,232	261
16	CPL - DOM	Interface	500	$0.2	$0.1	$0.4	$0.6	$0.0	$0.6	263	98
17	Messic Road - Ridgeley	Line	APS	$0.4	$0.0	$0.4	$0.5	$0.0	$0.5	113	0
18	Flint Lake - Luchtman Road	Flowgate	MISO	$0.6	$0.1	$0.7	$0.2	$0.2	$0.4	890	365
19	Northport - Albion	Flowgate	MISO	$0.3	($0.0)	$0.3	$0.3	$0.1	$0.4	132	28
20	Gardners - Texas East	Line	Met-Ed	$0.2	$0.1	$0.3	$0.3	$0.0	$0.3	2,258	341
	Top 20 Total			$46.7	$2.1	$48.7	$44.3	$2.3	$46.6	14,450	4,628
	All Other Constraints			($2.4)	$1.7	($0.7)	$6.2	($0.7)	$5.5	56,039	11,762
	Total			$44.3	$3.8	$48.1	$50.6	$1.5	$52.1	70,489	16,390

PPL Control Zone

Table 11-37 PPL Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	5004/5005 Interface	Interface	500	($8.9)	$3.8	($5.1)	$7.8	$0.3	$8.1	174	47
2	Cloverdale	Transformer	AEP	($3.4)	$2.6	($0.8)	$5.2	$0.2	$5.4	615	99
3	Northwood - Northwood Tap	Line	Met-Ed	$2.1	($2.8)	($0.8)	$0.2	($2.6)	($2.5)	56	72
4	Lakeview - Greenfield	Line	ATSI	($2.5)	$2.6	$0.1	$2.3	$0.1	$2.4	1,337	339
5	Wescosville	Transformer	PPL	$1.9	$1.8	$3.7	$1.3	$1.0	$2.3	104	52
6	AEP - DOM	Interface	500	($1.3)	$0.7	($0.7)	$2.1	$0.1	$2.2	664	150
7	Graceton - Safe Harbor	Line	BGE	$2.3	($3.1)	($0.8)	$0.0	($2.0)	($2.0)	2,986	1,805
8	North Meshoppen - Oxbow	Line	PENELEC	($1.7)	$2.0	$0.3	$0.9	$0.7	$1.6	487	164
9	East Townada - North Meshoppen	Line	PENELEC	($1.8)	$0.0	($1.8)	$1.3	$0.0	$1.3	605	0
10	Elimsport - Sunbury	Line	PPL	$0.8	$0.0	$0.8	$0.8	$0.0	$0.8	103	6
11	Emilie - Falls	Line	PECO	($0.8)	$0.1	($0.7)	$0.8	$0.0	$0.8	1,321	242
12	Bedington - Black Oak	Interface	500	($0.1)	$0.1	$0.1	$0.8	$0.0	$0.8	307	52
13	Person - Sedge Hill	Line	Dominion	($0.5)	$0.2	($0.3)	$0.8	$0.0	$0.8	814	136
14	Brokaw - Leroy	Flowgate	MISO	($0.6)	$0.2	($0.4)	$0.5	$0.3	$0.8	1,232	261
15	West	Interface	500	($0.9)	$0.1	($0.8)	$0.8	$0.0	$0.8	66	11
16	Riverside	Line	BGE	($0.3)	$0.0	($0.2)	$0.7	$0.0	$0.7	265	69
17	Quarry - Steel City	Line	PPL	$0.7	$0.0	$0.7	$0.7	$0.0	$0.7	0	0
18	North Meshoppen	Transformer	PENELEC	($2.6)	$0.4	($2.3)	$0.2	$0.5	$0.7	339	71
19	Flint Lake - Luchtman Road	Flowgate	MISO	($0.4)	$0.1	($0.2)	$0.3	$0.3	$0.6	890	365
20	Northport - Albion	Flowgate	MISO	($0.4)	$0.1	($0.3)	$0.4	$0.1	$0.5	132	28
	Top 20 Total			($18.3)	$8.7	($9.6)	$27.8	($1.0)	$26.8	12,497	3,969
	All Other Constraints			$29.2	$3.0	$32.2	$11.3	($2.2)	$9.1	60,753	12,480
	Total			$10.9	$11.7	$22.6	$39.1	($3.2)	$36.0	73,250	16,449

PSEG Control Zone

Table 11-38 PSEG Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Cedar Grove Sub - Roseland	Line	PSEG	$9.0	($0.2)	$8.8	$7.0	$0.3	$7.3	1,328	64
2	5004/5005 Interface	Interface	500	$5.3	($1.1)	$4.2	$6.2	$0.2	$6.4	174	47
3	Emilie - Falls	Line	PECO	$7.1	($0.1)	$7.1	$6.0	$0.3	$6.3	1,321	242
4	Cloverdale	Transformer	AEP	$1.6	($1.3)	$0.3	$4.4	$0.2	$4.6	615	99
5	Cedar Grove - Clifton	Line	PSEG	$5.2	($0.2)	$5.0	$3.5	($0.0)	$3.5	246	24
6	AEP - DOM	Interface	500	$0.4	($0.5)	($0.1)	$1.6	$0.1	$1.7	664	150
7	Northwood	Transformer	Met-Ed	$1.1	($0.0)	$1.1	$1.6	$0.0	$1.6	64	15
8	Lakeview - Greenfield	Line	ATSI	$0.2	($1.2)	($1.0)	$1.5	$0.1	$1.6	1,337	339
9	Graceton - Safe Harbor	Line	BGE	$0.8	($0.0)	$0.7	$0.0	($1.5)	($1.5)	2,986	1,805
10	Northwood - Northwood Tap	Line	Met-Ed	$0.9	($0.9)	($0.1)	$1.3	$0.2	$1.5	56	72
11	Federals - Newark	Line	PSEG	$1.6	$0.0	$1.6	$1.3	$0.0	$1.3	561	0
12	East	Interface	500	$0.3	($0.0)	$0.3	$1.0	$0.0	$1.0	106	2
13	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.8	$0.0	$0.8	814	136
14	Rad Essex - Newark Energy Center	Line	PSEG	$0.8	$0.0	$0.8	$0.8	$0.0	$0.8	0	0
15	Wescosville	Transformer	PPL	$0.1	($0.2)	($0.1)	$0.4	$0.4	$0.8	104	52
16	Bedington - Black Oak	Interface	500	($0.0)	($0.1)	($0.1)	$0.7	$0.0	$0.7	307	52
17	Riverside	Line	BGE	$0.1	($0.1)	$0.1	$0.7	$0.0	$0.7	265	69
18	Brokaw - Leroy	Flowgate	MISO	$0.3	($0.2)	$0.1	$0.5	$0.2	$0.7	1,232	261
19	West	Interface	500	$0.5	($0.1)	$0.4	$0.6	$0.0	$0.7	66	11
20	East Townada - North Meshoppen	Line	PENELEC	$0.3	$0.0	$0.3	$0.7	$0.0	$0.7	605	0
	Top 20 Total			$35.8	($6.4)	$29.4	$40.7	$0.4	$41.1	12,851	3,440
	All Other Constraints			$9.6	$0.4	$10.0	$12.6	($1.7)	$10.9	60,689	13,009
	Total			$45.4	($6.0)	$39.4	$53.3	($1.2)	$52.0	73,540	16,449

RECO Control Zone

Table 11-39 RECO Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Lenox - Williams Potter	Line	PENELEC	$0.1	($0.0)	$0.1	$0.9	$0.0	$0.9	383	8
2	Cedar Grove Sub - Roseland	Line	PSEG	$0.6	$0.0	$0.6	$0.3	$0.0	$0.3	1,328	64
3	Burns - Corporate Road	Line	RECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	326	0
4	5004/5005 Interface	Interface	500	$0.4	$0.0	$0.5	$0.2	$0.0	$0.2	174	47
5	Maywood - Saddlebrook	Line	PSEG	$0.4	($0.7)	($0.2)	$0.2	$0.0	$0.2	378	98
6	Emilie - Falls	Line	PECO	$0.3	($0.0)	$0.3	$0.2	$0.0	$0.2	1,321	242
7	Cloverdale	Transformer	AEP	$0.2	$0.0	$0.2	$0.1	$0.0	$0.1	615	99
8	Williams Midstream - Williams Potter	Line	PENELEC	($0.0)	$0.0	($0.0)	$0.1	$0.0	$0.1	43	0
9	East Towanda - Hillside	Line	PENELEC	$0.1	($0.0)	$0.1	$0.1	$0.0	$0.1	468	94
10	Cedar Grove - Clifton	Line	PSEG	$0.1	$0.0	$0.1	$0.1	($0.0)	$0.1	246	24
11	Tiffany - Williams	Line	PENELEC	$0.0	$0.0	$0.0	$0.1	$0.0	$0.1	22	0
12	Ramapo (ConEd) - S Mahwah (RECO)	Line	RECO	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	65	0
13	Northwood	Transformer	Met-Ed	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	64	15
14	Northwood - Northwood Tap	Line	Met-Ed	$0.1	$0.0	$0.1	$0.0	$0.0	$0.1	56	72
15	Graceton - Safe Harbor	Line	BGE	($0.7)	($0.6)	($1.3)	$0.0	($0.0)	($0.0)	2,986	1,805
16	Everts Drive - South Troy	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	222	0
17	Lenox - North Meshoppen	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	1
18	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	49	0
19	AEP - DOM	Interface	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	664	150
20	East	Interface	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	106	2
	Top 20 Total			$2.2	($1.3)	$0.9	$2.8	($0.0)	$2.8	9,548	2,721
	All Other Constraints			($2.9)	$0.7	($2.2)	$0.5	($0.0)	$0.4	60,862	13,669
	Total			($0.7)	($0.6)	($1.2)	$3.2	($0.0)	$3.2	70,410	16,390

West Region Congestion-Event Summaries

AEP Control Zone

Table 11-40 AEP Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$94.3	($11.1)	$83.2	$30.6	$0.3	$30.9	664	150
2	Capitol Hill - Chemical	Line	AEP	$17.4	$0.9	$18.3	$17.0	$1.2	$18.2	508	98
3	Cloverdale	Transformer	AEP	$51.7	($4.1)	$47.6	$9.5	($0.4)	$9.1	615	99
4	Graceton - Safe Harbor	Line	BGE	($3.9)	$0.6	($3.3)	$7.9	$0.3	$8.2	2,986	1,805
5	Northport - Albion	Flowgate	MISO	$7.8	$0.7	$8.5	$6.3	$1.0	$7.3	132	28
6	Tanners Creek - Miami Fort	Flowgate	MISO	$25.8	$0.0	$25.8	$5.6	$0.0	$5.6	1,346	0
7	Delco Remy - Fall Creek	Line	AEP	$4.7	($1.1)	$3.6	$5.3	($0.2)	$5.1	247	18
8	Hazard	Transformer	AEP	$4.1	$0.3	$4.3	$4.1	$0.6	$4.7	143	17
9	Conastone - Peach Bottom	Line	500	($2.8)	($0.2)	($3.0)	$3.9	$0.2	$4.2	997	393
10	Broadford - Saltville	Line	AEP	$3.7	$0.3	$4.0	$3.4	$0.6	$3.9	343	51
11	Huntington Junction - Sorenson	Line	AEP	$2.8	$0.0	$2.8	$3.7	$0.0	$3.7	878	0
12	Flint Lake - Luchtman Road	Flowgate	MISO	$2.5	($0.3)	$2.1	$1.7	$1.6	$3.3	890	365
13	Olive	Flowgate	MISO	$4.7	$0.0	$4.7	$3.2	$0.0	$3.2	445	0
14	Broadford - Smyth	Line	AEP	$3.1	($0.5)	$2.6	$2.9	$0.2	$3.1	138	49
15	Maple - Jackson	Line	ATSI	($0.6)	($0.2)	($0.7)	$3.0	$0.0	$3.0	775	135
16	Grant - Greentown	Line	AEP	$2.4	$0.0	$2.4	$2.6	$0.0	$2.6	391	0
17	Brokaw - Leroy	Flowgate	MISO	($6.7)	$2.0	($4.7)	$1.6	$1.0	$2.6	1,232	261
18	Volunteer - Phipps Bend	Flowgate	MISO	$1.0	$1.2	$2.3	$0.9	$1.5	$2.4	7	38
19	Lakeview - Greenfield	Line	ATSI	($0.5)	($2.4)	($2.9)	$1.2	($3.6)	($2.4)	1,337	339
20	Northwest Tap - Purdue	Flowgate	MISO	$4.3	$0.0	$4.3	$2.0	$0.2	$2.2	444	236
	Top 20 Total			$215.7	($13.8)	$201.9	$116.4	$4.5	$120.8	14,518	4,082
	All Other Constraints			$120.1	($17.4)	$102.7	$70.7	($3.5)	$67.2	62,194	12,463
	Total			$335.8	($31.2)	$304.6	$187.1	$1.0	$188.1	76,712	16,545

APS Control Zone

Table 11-41 APS Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Cloverdale	Transformer	AEP	$7.7	($0.3)	$7.4	$5.7	$0.2	$6.0	615	99
2	Gardners - Texas East	Line	Met-Ed	$3.7	$0.4	$4.1	$4.4	$0.2	$4.6	2,258	341
3	AEP - DOM	Interface	500	$8.8	$0.5	$9.2	$3.9	$0.1	$4.0	664	150
4	Graceton - Safe Harbor	Line	BGE	$1.7	($0.8)	$0.8	$3.3	$0.1	$3.4	2,986	1,805
5	Lakeview - Greenfield	Line	ATSI	$2.0	$0.1	$2.0	$2.8	$0.1	$2.9	1,337	339
6	Bedington - Black Oak	Interface	500	$5.8	$0.5	$6.3	$2.8	$0.1	$2.8	307	52
7	Yukon	Transformer	500	$2.9	$0.2	$3.0	$1.9	$0.1	$2.0	102	58
8	East Waynesboro - Ringgold	Line	APS	$1.7	$0.0	$1.7	$1.9	$0.0	$1.9	49	0
9	Tiltonsville - Windsor	Line	APS	$3.0	$0.1	$3.1	$1.7	$0.0	$1.8	355	9
10	Conastone - Peach Bottom	Line	500	$0.8	($0.2)	$0.5	$1.6	$0.1	$1.6	997	393
11	AP South	Interface	500	$6.0	($0.0)	$5.9	$1.5	($0.0)	$1.4	447	31
12	502 Junction	Transformer	500	$2.0	$0.0	$2.0	$1.4	$0.0	$1.4	37	0
13	Layman - Wolf Creek	Line	AEP	($0.4)	$0.1	($0.3)	$1.2	$0.0	$1.2	438	12
14	Brokaw - Leroy	Flowgate	MISO	$0.3	$0.0	$0.3	$0.6	$0.3	$1.0	1,232	261
15	Capitol Hill - Chemical	Line	AEP	$0.5	$0.1	$0.5	$0.8	$0.1	$0.9	508	98
16	Lincoln - Straban	Line	PENELEC	$1.5	($0.1)	$1.4	$0.9	$0.0	$0.9	603	189
17	Monroe - Lallendorf	Flowgate	MISO	$0.1	$0.0	$0.1	$0.8	$0.0	$0.8	945	0
18	Flint Lake - Luchtman Road	Flowgate	MISO	$0.4	($0.0)	$0.3	$0.4	$0.4	$0.7	890	365
19	Conastone - Northwest	Line	BGE	$0.4	$0.1	$0.5	$0.6	$0.1	$0.7	234	156
20	Northport - Albion	Flowgate	MISO	$0.1	($0.0)	$0.1	$0.5	$0.1	$0.7	132	28
	Top 20 Total			$48.9	$0.4	$49.3	$38.6	$2.1	$40.7	15,136	4,386
	All Other Constraints			$2.3	($1.8)	$0.5	$12.9	($0.2)	$12.8	58,642	12,006
	Total			$51.2	($1.4)	$49.9	$51.6	$1.9	$53.5	73,778	16,392

ATSI Control Zone

Table 11-42 ATSI Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Lakeview - Greenfield	Line	ATSI	$34.9	($12.3)	$22.5	$16.3	($1.8)	$14.5	1,337	339
2	Maple - Jackson	Line	ATSI	$9.6	($0.3)	$9.3	$7.4	$0.0	$7.5	775	135
3	Gable Switch Station - South Cadiz	Line	AEP	$4.6	($1.0)	$3.7	$6.1	$0.0	$6.1	284	106
4	Monroe - Lallendorf	Flowgate	MISO	$3.1	$0.0	$3.1	$5.2	$0.0	$5.2	945	0
5	Krendale - Shanorma	Line	APS	$5.8	$0.0	$5.8	$2.8	$0.0	$2.8	440	0
6	Buckhorn - West Coshocton	Line	AEP	$1.2	($0.0)	$1.1	$2.1	$0.0	$2.1	147	4
7	Lockwood - South Hicksville	Line	AEP	$1.4	($0.3)	$1.1	$1.9	$0.2	$2.1	444	91
8	Butler - Shanor Manor	Line	APS	$4.5	($0.2)	$4.3	$2.1	$0.0	$2.1	381	93
9	New Comerstown - South Coshoct	Line	AEP	$1.5	($0.1)	$1.5	$2.0	$0.0	$2.1	266	44
10	Yukon	Transformer	500	$2.2	($0.3)	$1.9	$1.8	$0.1	$1.9	102	58
11	Toronto	Other	ATSI	$1.7	$3.9	$5.5	$1.3	$0.5	$1.9	59	44
12	Graceton - Safe Harbor	Line	BGE	$3.1	($0.8)	$2.2	$1.3	$0.1	$1.4	2,986	1,805
13	Conastone - Peach Bottom	Line	500	$2.0	($0.4)	$1.6	$1.1	$0.1	$1.2	997	393
14	Morocco - Allen Junction	Flowgate	MISO	$0.7	$0.0	$0.7	$1.1	$0.0	$1.1	23	0
15	Brokaw - Leroy	Flowgate	MISO	$1.3	($0.1)	$1.2	$0.8	$0.3	$1.1	1,232	261
16	Flint Lake - Luchtman Road	Flowgate	MISO	$2.0	($0.3)	$1.6	$0.5	$0.5	$1.1	890	365
17	Mitchell - Wilson	Line	APS	$1.3	($0.1)	$1.2	$1.0	$0.0	$1.0	297	13
18	Northport - Albion	Flowgate	MISO	$0.3	$0.1	$0.4	$0.7	$0.2	$0.9	132	28
19	Bay Shore	Transformer	ATSI	$0.9	($1.2)	($0.3)	$0.9	$0.0	$0.9	75	43
20	AEP - DOM	Interface	500	($7.2)	($1.2)	($8.4)	$0.0	($0.8)	($0.8)	664	150
	Top 20 Total			$74.7	($14.7)	$60.0	$56.6	($0.5)	$56.2	12,476	3,972
	All Other Constraints			$5.5	($4.3)	$1.1	$24.3	$0.1	$24.5	59,648	12,571
	Total			$80.1	($19.0)	$61.1	$81.0	($0.3)	$80.7	72,124	16,543

ComEd Control Zone

Table 11-43 ComEd Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Roxana - Praxair	Flowgate	MISO	($3.8)	$5.4	$1.6	($0.1)	($7.8)	($7.9)	769	405
2	Davis	Transformer	ComEd	$5.5	$0.0	$5.5	$5.5	$0.0	$5.5	409	10
3	Graceton - Safe Harbor	Line	BGE	($4.5)	($2.2)	($6.7)	$5.2	$0.2	$5.4	2,986	1,805
4	Notre Dame - South Bend	Line	AEP	$0.4	($0.9)	($0.5)	$0.0	($4.9)	($4.9)	44	47
5	Tanners Creek - Miami Fort	Line	AEP	$1.4	$3.1	$4.4	$0.0	($4.2)	($4.2)	509	435
6	Quad Cities - Cordova	Flowgate	MISO	$5.8	$0.0	$5.8	$4.2	$0.0	$4.2	1,033	0
7	Quad Cities	Transformer	ComEd	$4.1	$0.0	$4.1	$4.1	$0.0	$4.1	48	0
8	Greentown	Flowgate	MISO	$0.1	($0.3)	($0.2)	$0.0	($3.9)	($3.9)	121	72
9	Lakeview - Greenfield	Line	ATSI	$8.8	$3.6	$12.4	$0.0	($3.7)	($3.7)	1,337	339
10	Silver lake	Transformer	ComEd	$3.7	$0.0	$3.7	$3.6	$0.0	$3.6	104	0
11	Conastone - Peach Bottom	Line	500	($1.9)	$0.0	($1.8)	$2.9	$0.1	$3.0	997	393
12	Dearborn - Pierce	Flowgate	MISO	$0.5	($3.0)	($2.5)	$0.0	($2.9)	($2.9)	67	49
13	Flint Lake - Luchtman Road	Flowgate	MISO	($0.6)	$7.8	$7.2	$0.0	($2.3)	($2.3)	890	365
14	Fargo	Flowgate	MISO	$1.9	($0.9)	$0.9	$2.1	$0.0	$2.1	528	305
15	Maple - Jackson	Line	ATSI	($0.6)	($0.4)	($1.1)	$2.0	$0.0	$2.0	775	135
16	Belvidere - Chrysler Corp.	Line	ComEd	$1.8	$0.0	$1.8	$1.9	$0.0	$1.9	156	0
17	Cherry Valley	Transformer	ComEd	$1.8	$0.0	$1.8	$1.8	$0.0	$1.8	325	1
18	Nelson	Flowgate	MISO	$1.7	$0.0	$1.7	$1.7	$0.0	$1.7	155	0
19	Lallendorf - Monroe	Line	ATSI	$0.0	$3.6	$3.6	$0.0	($1.7)	($1.7)	10	208
20	Krendale - Shanorma	Line	APS	($0.9)	$0.0	($0.9)	$1.5	$0.0	$1.5	440	0
	Top 20 Total			$25.1	$15.7	$40.8	$36.5	($31.1)	$5.5	11,703	4,569
	All Other Constraints			$132.6	$28.3	$160.9	$25.7	($16.0)	$9.8	62,713	11,977
	Total			$157.7	$44.0	$201.7	$62.2	($47.0)	$15.2	74,416	16,546

DAY Control Zone

Table 11-44 DAY Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	Flowgate	MISO	$4.6	$0.0	$4.6	$11.2	$0.0	$11.2	1,346	0
2	Batesville - Hubble	Flowgate	MISO	$1.9	$0.6	$2.5	$4.9	$0.5	$5.5	254	134
3	Tanners Creek - Miami Fort	Line	AEP	$0.3	$1.5	$1.8	$1.1	$0.7	$1.8	509	435
4	Emerald - Kenton	Line	AEP	$0.5	$0.0	$0.5	$1.6	$0.0	$1.6	458	90
5	Pierce - Beckjord	Flowgate	MISO	$0.6	$0.0	$0.6	$1.0	$0.0	$1.0	263	0
6	Pierce	Transformer	DEOK	$0.7	$0.0	$0.7	$1.0	$0.0	$1.0	291	0
7	Graceton - Safe Harbor	Line	BGE	$1.4	$0.3	$1.7	$1.0	$0.0	$1.0	2,986	1,805
8	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$0.6	($0.0)	$0.6	$0.8	$0.0	$0.8	271	3
9	Lakeview - Greenfield	Line	ATSI	($2.3)	($0.6)	($2.9)	$0.0	($0.6)	($0.6)	1,337	339
10	Conastone - Peach Bottom	Line	500	$1.3	($0.1)	$1.2	$0.5	$0.0	$0.5	997	393
11	Terminal	Transformer	DEOK	($0.0)	$0.0	$0.0	$0.5	$0.0	$0.5	272	17
12	Trenton - College Crn	Line	DAY	$0.3	$0.0	$0.3	$0.5	$0.0	$0.5	129	0
13	Pierce - Foster	Flowgate	MISO	$0.2	$0.0	$0.2	$0.4	$0.0	$0.4	88	0
14	Maple - Jackson	Line	ATSI	$0.4	($0.1)	$0.3	$0.4	$0.0	$0.4	775	135
15	Delaware - Hogan	Line	AEP	$0.1	$0.0	$0.2	$0.4	$0.0	$0.4	398	11
16	Brokaw - Leroy	Flowgate	MISO	$0.3	$0.1	$0.4	$0.2	$0.2	$0.4	1,232	261
17	logtown - North Delphos	Line	AEP	$0.2	$0.0	$0.2	$0.4	$0.0	$0.4	174	0
18	Delaware - Watkins Tap	Line	AEP	$0.6	$0.0	$0.6	$0.4	$0.0	$0.4	147	0
19	AEP - DOM	Interface	500	($0.9)	($1.4)	($2.3)	$0.0	($0.4)	($0.4)	664	150
20	Dearborn - Pierce	Flowgate	MISO	$0.2	($0.4)	($0.2)	$0.2	$0.1	$0.3	67	49
	Top 20 Total			$11.0	($0.0)	$10.9	$26.4	$0.6	$27.1	12,658	3,822
	All Other Constraints			$2.1	($1.4)	$0.8	$6.8	$0.1	$6.9	62,720	12,723
	Total			$13.1	($1.4)	$11.7	$33.2	$0.7	$33.9	75,378	16,545

DEOK Control Zone

Table 11-45 DEOK Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	Flowgate	MISO	$28.8	$0.0	$28.8	$45.6	$0.0	$45.6	1,346	0
2	Batesville - Hubble	Flowgate	MISO	$21.2	$0.4	$21.7	$26.0	$3.0	$29.0	254	134
3	Tanners Creek - Miami Fort	Line	AEP	$2.2	$0.3	$2.5	$4.8	$4.4	$9.1	509	435
4	Pierce	Transformer	DEOK	$4.7	$0.0	$4.7	$5.6	$0.0	$5.6	291	0
5	Pierce - Beckjord	Flowgate	MISO	$4.7	$0.0	$4.7	$5.5	$0.0	$5.5	263	0
6	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$3.9	($0.0)	$3.9	$4.6	$0.0	$4.6	271	3
7	Terminal	Transformer	DEOK	$3.1	$0.0	$3.2	$4.5	$0.1	$4.6	272	17
8	Graceton - Safe Harbor	Line	BGE	$3.4	($0.6)	$2.8	$1.6	$0.1	$1.7	2,986	1,805
9	East Bend	Transformer	DEOK	$1.5	$0.0	$1.5	$1.5	$0.0	$1.5	64	0
10	Beckjord - Pierce	Line	DEOK	$1.1	($0.2)	$0.9	$1.4	$0.1	$1.5	145	75
11	Buffington - Florence	Line	DEOK	$0.9	($0.0)	$0.9	$1.2	($0.0)	$1.2	65	4
12	College Corner - Collinsville	Line	AEP	$1.0	($0.0)	$1.0	$1.1	$0.0	$1.1	175	3
13	Emerald - Kenton	Line	AEP	$0.4	($0.1)	$0.3	$1.0	($0.0)	$1.0	458	90
14	Dearborn - Pierce	Flowgate	MISO	$0.6	($0.2)	$0.4	$0.6	$0.3	$0.9	67	49
15	Conastone - Peach Bottom	Line	500	$1.4	($0.4)	$1.0	$0.9	$0.0	$0.9	997	393
16	Miami Fort	Transformer	DEOK	$0.9	($0.0)	$0.8	$0.9	$0.0	$0.9	10	2
17	Lakeview - Greenfield	Line	ATSI	($2.5)	($0.9)	($3.4)	$0.0	($0.8)	($0.8)	1,337	339
18	Silver Grove	Other	DEOK	$0.8	$0.0	$0.8	$0.8	$0.0	$0.8	35	0
19	Grant - Greentown	Line	AEP	$0.3	$0.0	$0.3	$0.7	$0.0	$0.7	391	0
20	Brokaw - Leroy	Flowgate	MISO	$0.5	$0.1	$0.6	$0.3	$0.4	$0.7	1,232	261
	Top 20 Total			$79.0	($1.6)	$77.4	$108.5	$7.6	$116.0	11,168	3,610
	All Other Constraints			($8.2)	($7.7)	($15.9)	$11.9	($1.1)	$10.8	59,357	12,935
	Total			$70.7	($9.3)	$61.5	$120.4	$6.5	$126.9	70,525	16,545

DLCO Control Zone

Table 11-46 DLCO Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)						Event Hours	
				Area Based			Constraint Based				
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Lakeview - Greenfield	Line	ATSI	($2.7)	$1.0	($1.7)	$2.0	$0.1	$2.1	1,337	339
2	Mitchell - Wilson	Line	APS	$2.1	$0.0	$2.1	$1.3	$0.0	$1.4	297	13
3	Maple - Jackson	Line	ATSI	($1.0)	($0.1)	($1.2)	$1.2	$0.0	$1.2	775	135
4	Crescent - Mt. Nebo	Line	DLCO	$0.0	$1.3	$1.3	$0.0	$1.1	$1.1	0	22
5	Yukon	Transformer	500	$0.4	$0.3	$0.7	$0.9	$0.0	$1.0	102	58
6	Brunot Island - Collier	Line	DLCO	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	198	2
7	Crescent - Mt Nebo	Line	DLCO	$1.1	$0.0	$1.1	$0.7	$0.0	$0.7	58	0
8	New Comerstown - South Coshoct	Line	AEP	$0.0	($0.0)	$0.0	$0.6	$0.0	$0.6	266	44
9	Buckhorn - West Coshocton	Line	AEP	$0.0	$0.0	$0.0	$0.6	$0.0	$0.6	147	4
10	Tiltonsville - Windsor	Line	APS	$0.6	$0.0	$0.6	$0.5	$0.0	$0.5	355	9
11	Krendale - Shanorma	Line	APS	($0.3)	$0.0	($0.3)	$0.5	$0.0	$0.5	440	0
12	Monroe - Lallendorf	Flowgate	MISO	($0.4)	$0.0	($0.4)	$0.5	$0.0	$0.5	945	0
13	Toronto	Other	ATSI	($0.4)	$0.1	($0.3)	$0.3	$0.1	$0.4	59	44
14	Butler - Shanor Manor	Line	APS	($0.2)	($0.0)	($0.2)	$0.4	$0.0	$0.4	381	93
15	Collier - Tidd	Line	AEP	$0.1	$0.0	$0.1	$0.3	$0.0	$0.3	44	0
16	Muskingum River - South Caldwell	Line	AEP	$0.0	($0.0)	$0.0	$0.3	$0.0	$0.3	48	28
17	Conastone - Peach Bottom	Line	500	$0.1	($0.1)	$0.0	$0.3	$0.0	$0.3	997	393
18	Graceton - Safe Harbor	Line	BGE	($0.0)	($0.1)	($0.2)	$0.2	$0.0	$0.3	2,986	1,805
19	Peters - Union Jct	Line	APS	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	16	0
20	Brokaw - Leroy	Flowgate	MISO	($0.2)	$0.1	($0.2)	$0.2	$0.1	$0.2	1,232	261
	Top 20 Total			$0.3	$2.5	$2.8	$11.8	$1.5	$13.3	10,683	3,250
	All Other Constraints			$5.1	($1.6)	$3.6	$3.9	($0.4)	$3.4	56,264	13,140
	Total			$5.4	$0.9	$6.3	$15.6	$1.1	$16.7	66,947	16,390

EKPC Control Zone

Table 11-47 EKPC Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	Flowgate	MISO	($2.6)	$0.0	($2.6)	$4.2	$0.0	$4.2	1,346	0
2	Tanners Creek - Miami Fort	Line	AEP	($0.1)	$0.0	($0.1)	$0.6	$0.5	$1.1	509	435
3	Graceton - Safe Harbor	Line	BGE	$0.9	$0.3	$1.2	$0.9	$0.0	$0.9	2,986	1,805
4	Brokaw - Leroy	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.3	$0.3	$0.5	1,232	261
5	Quad Cities - Cordova Energy	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.5)	($0.5)	0	240
6	Lakeview - Greenfield	Line	ATSI	($0.9)	$0.4	($0.4)	$0.0	($0.5)	($0.5)	1,337	339
7	Conastone - Peach Bottom	Line	500	$0.3	$0.1	$0.4	$0.4	$0.0	$0.4	997	393
8	Broadford - Saltville	Line	AEP	$0.3	($0.3)	$0.1	$0.4	$0.1	$0.4	343	51
9	Batesville - Hubble	Flowgate	MISO	($11.0)	$0.2	($10.8)	$0.6	($0.2)	$0.3	254	134
10	Kenton - Spurlock	Line	EKPC	$1.5	($0.1)	$1.4	$0.0	($0.2)	($0.2)	231	184
11	Eugene - Cayuga	Flowgate	MISO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	293	23
12	Northport - Albion	Flowgate	MISO	$0.1	$0.0	$0.1	$0.2	$0.0	$0.2	132	28
13	Maple - Jackson	Line	ATSI	$0.1	($0.0)	$0.1	$0.2	$0.0	$0.2	775	135
14	Krendale - Shanorma	Line	APS	$0.0	$0.0	$0.0	$0.2	$0.0	$0.2	440	0
15	Emerald - Kenton	Line	AEP	$1.3	($0.2)	$1.2	$0.0	($0.2)	($0.2)	458	90
16	AEP - DOM	Interface	500	$1.5	$1.2	$2.7	$0.4	($0.2)	$0.2	664	150
17	Nottingham	Other	PECO	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	606	295
18	Pierce - Beckjord	Flowgate	MISO	($0.4)	$0.0	($0.4)	$0.2	$0.0	$0.2	263	0
19	Butler - Shanor Manor	Line	APS	$0.0	$0.0	$0.1	$0.2	$0.0	$0.2	381	93
20	Conastone - Northwest	Line	BGE	$0.1	($0.0)	$0.1	$0.1	$0.0	$0.2	234	156
	Top 20 Total			($8.1)	$1.7	($6.4)	$9.0	($0.9)	$8.2	13,481	4,812
	All Other Constraints			($9.1)	$3.0	($6.1)	$2.7	($1.1)	$1.6	56,417	11,733
	Total			($17.2)	$4.7	($12.5)	$11.7	($2.0)	$9.7	69,898	16,545

South Region Congestion-Event Summaries

Dominion Control Zone

Table 11-48 Dominion Control Zone top congestion cost impacts (By facility): January through September, 2018

				Congestion Costs (Millions)						Event Hours	
				Area Based			Constraint Based				
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$11.8	($2.3)	$9.5	$59.6	$4.9	$64.5	664	150
2	Cloverdale	Transformer	AEP	$11.5	$1.1	$12.6	$32.6	$1.4	$34.0	615	99
3	Graceton - Safe Harbor	Line	BGE	$7.9	($2.1)	$5.8	$18.5	$0.6	$19.1	2,986	1,805
4	AP South	Interface	500	$6.4	($0.0)	$6.4	$11.1	$0.0	$11.1	447	31
5	Person - Sedge Hill	Line	Dominion	$5.6	($0.4)	$5.1	$9.4	$0.4	$9.8	814	136
6	Bedington - Black Oak	Interface	500	$4.2	($0.2)	$4.0	$8.3	$0.2	$8.5	307	52
7	Conastone - Peach Bottom	Line	500	$0.0	$0.0	$0.1	$7.7	$0.4	$8.1	997	393
8	Pleasant View - Ashburn	Line	Dominion	$9.1	$0.0	$9.1	$7.2	$0.0	$7.2	148	4
9	CPL - DOM	Interface	500	$5.6	($1.2)	$4.4	$5.4	$0.1	$5.5	263	98
10	Conastone - Northwest	Line	BGE	$0.7	$0.3	$1.0	$3.1	$0.3	$3.4	234	156
11	Nottingham	Other	PECO	$1.0	$0.0	$1.0	$3.2	$0.0	$3.2	606	295
12	Bagley - Graceton	Line	BGE	$0.1	($0.1)	($0.1)	$2.5	$0.0	$2.6	458	182
13	Brokaw - Leroy	Flowgate	MISO	$0.5	($0.2)	$0.4	$1.4	$0.8	$2.2	1,232	261
14	Lincoln - Straban	Line	PENELEC	$0.2	($0.0)	$0.1	$2.0	$0.1	$2.1	603	189
15	Gardners - Texas East	Line	Met-Ed	$0.3	($0.1)	$0.2	$1.8	$0.2	$2.0	2,258	341
16	Bremo - Cartersville	Line	Dominion	$1.7	$0.1	$1.8	$1.7	$0.1	$1.8	21	11
17	Face Rock	Other	PPL	$0.4	$0.0	$0.4	$1.5	$0.0	$1.5	541	0
18	Northport - Albion	Flowgate	MISO	$0.2	($0.0)	$0.2	$1.3	$0.2	$1.4	132	28
19	Flint Lake - Luchtman Road	Flowgate	MISO	$0.7	($0.0)	$0.7	$0.7	$0.6	$1.3	890	365
20	Beaumeade - Ashburn	Line	Dominion	$1.4	$0.0	$1.4	$1.1	$0.0	$1.1	10	0
	Top 20 Total			$69.3	($5.2)	$64.1	$180.1	$10.2	$190.3	14,226	4,596
	All Other Constraints			$10.7	$0.2	$10.9	$19.3	($3.0)	$16.3	58,022	11,796
	Total			$80.1	($5.0)	$75.0	$199.4	$7.2	$206.6	72,248	16,392

Congestion Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated method for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[26] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[27] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of September 30, 2018, PJM had 131 flowgates eligible for M2M (Market to Market) coordination and MISO had 215 flowgates eligible for M2M coordination.

Table 11-49 and Table 11-50 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2018 and 2017, 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 the first nine months of 2018, the Tanners Creek – Miami Fort Flowgate made the most significant contribution to positive congestion while the Greentown Flowgate contributed to most negative congestion.

26 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>.

27 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 11-49 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September, 2018

		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	Tanners Creek - Miami Fort	($19.7)	($90.0)	($2.9)	$67.3	$0.0	$0.0	$0.0	$0.0	$67.3	1,346	0
2	Batesville - Hubble	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.4	$2.0	$34.5	254	134
3	Northport - Albion	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	132	28
4	Brokaw - Leroy	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1,232	261
5	Monroe - Lallendorf	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	945	0
6	Flint Lake - Luchtman Road	$0.2	($10.6)	($4.9)	$5.8	($0.2)	($1.4)	$1.7	$2.9	$8.7	890	365
7	Olive	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	445	0
8	Pierce - Beckjord	($2.2)	($9.1)	($0.1)	$6.7	$0.0	$0.0	$0.0	$0.0	$6.7	263	0
9	Quad Cities - Cordova	($3.9)	($8.5)	$1.9	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	1,035	0
10	Volunteer - Phipps Bend	($0.3)	($2.9)	($0.7)	$1.9	($1.0)	($3.2)	$1.2	$3.4	$5.3	7	38
11	Burnham - Munster	$0.6	($4.0)	($0.1)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	751	0
12	Plymouth - Leesburg	($1.9)	($7.7)	($2.0)	$3.7	($0.5)	$0.4	$1.5	$0.6	$4.4	306	163
13	Greentown	($0.0)	($0.7)	($0.2)	$0.5	($0.9)	$6.0	$2.1	($4.8)	($4.3)	121	72
14	Roxana - Praxair	$0.7	($3.7)	($3.2)	$1.2	$2.3	$1.8	($5.8)	($5.3)	($4.1)	769	405
15	Holland - Neoga	($0.6)	($4.3)	($0.1)	$3.5	$0.2	$0.0	$0.0	$0.2	$3.7	106	41
16	Braidwood - East Frankfurt	($0.0)	($3.6)	($0.0)	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	63	0
17	Northwest Tap - Purdue	($1.9)	($6.4)	($1.1)	$3.3	$1.1	$2.2	$1.2	$0.1	$3.4	444	236
18	Eugene - Cayuga	($0.4)	($4.4)	($0.6)	$3.4	$0.0	$0.0	($0.0)	($0.0)	$3.4	293	23
19	Newton	($0.5)	($2.9)	$0.1	$2.5	$0.2	$0.2	($0.2)	($0.3)	$2.2	1,116	389
20	Maroa - E GooseCreek	($0.0)	($2.0)	($0.5)	$1.5	$0.0	($0.1)	$0.3	$0.5	$2.0	189	54
	Top 20 Total	($45.9)	($265.5)	($33.1)	$186.5	$1.0	$1.3	$6.6	$6.3	$192.7	10,707	2,209
	All Other Constraints	($7.2)	($39.3)	($3.5)	$28.6	$0.4	$4.3	($5.1)	($8.9)	$19.6	4,986	2,023
	Total	($53.1)	($304.8)	($36.7)	$215.0	$1.5	$5.6	$1.5	($2.7)	$212.4	15,693	4,232

Table 11-50 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September, 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	($21.5)	($38.8)	$0.6	$17.9	$1.2	$0.8	($0.5)	($0.1)	$17.8	3,145	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	$5.9	$2.7	$9.1	483	244
4	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.9)	($0.5)	$0.4	$0.0	$5.6	425	248
5	Batesville - Hubble	($4.2)	($14.0)	($3.0)	$6.8	($0.1)	($1.1)	($2.4)	($1.3)	$5.4	140	105
6	Byron - Cherry Valley	($0.7)	($5.4)	($0.1)	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	175	0
7	Havana E - Havana S	($2.0)	($6.3)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	1,603	0
8	Nelson	($2.2)	($6.4)	($0.3)	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	509	0
9	Roxana - Praxair	($0.3)	$0.8	($0.4)	($1.5)	$1.3	$0.2	($3.3)	($2.2)	($3.6)	1,315	268
10	Brokaw - Leroy	$0.5	($3.4)	($1.8)	$2.2	($0.0)	$0.7	$1.7	$1.0	$3.2	803	317
11	Todd Hunter	($0.6)	($3.4)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	871	0
12	Olive - Bosserman	$1.2	($1.5)	($0.4)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	133	0
13	Shadelnd - Lafaysouth	($4.1)	($6.7)	$0.2	$2.8	$6.7	$4.8	($2.4)	($0.6)	$2.2	870	647
14	Dune Acres - Michigan City	($0.1)	($0.9)	($0.7)	$0.0	($0.1)	$0.0	($2.0)	($2.1)	($2.1)	125	70
15	Pleasant Prairie - Zion	($0.5)	($2.9)	($0.1)	$2.3	$0.0	$0.1	($0.2)	($0.2)	$2.1	1,555	278
16	Quad Cities	($0.9)	($2.8)	$0.2	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	236	0
17	Reynolds - Magnetation	($0.2)	($1.3)	$0.3	$1.4	$0.0	($0.0)	($0.1)	($0.0)	$1.4	256	22
18	Dresden	($0.1)	($1.6)	($0.2)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	312	0
19	Newton	($0.2)	($1.6)	($0.2)	$1.2	$0.1	($0.1)	($0.1)	$0.1	$1.3	514	173
20	Eugene - Cayuga	($0.4)	($1.9)	($0.2)	$1.3	$0.2	$0.0	($0.2)	($0.1)	$1.3	286	84
	Top 20 Total	($40.9)	($128.6)	($9.5)	$78.2	$6.3	$5.8	($3.3)	($2.8)	$75.5	14,095	2,654
	All Other Constraints	($4.0)	($23.5)	($5.2)	$14.2	($0.1)	$1.3	($3.2)	($4.6)	$9.7	5,440	1,765
	Total	($45.0)	($152.1)	($14.7)	$92.5	$6.3	$7.1	($6.4)	($7.3)	$85.2	19,535	4,419

Congestion Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated method 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.[28] 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.[29]

In the first nine months of 2018, none of the NYISO flowgates were binding and only one flowgate was binding in the first nine months of 2017. Table 11-51 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first nine months of 2017.

28 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>.
29 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>.

Table 11-51 Congestion cost impact from NYISO flowgates affecting PJM dispatch (By facility): January through September, 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	1
	Total			($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	21

Congestion Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-52 and Table 11-53 show the 500 kV constraints affecting congestion costs in PJM for the first nine months of 2018 and 2017. 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 11-52 Regional constraints summary (By facility): January through September, 2018

			Congestion Costs (Millions)										
			Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	$55.2	($66.6)	($5.2)	$116.6	$13.4	$18.7	$9.0	$3.8	$120.4	664	150
2	5004/5005 Interface	Interface	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	174	47
3	Conastone - Peach Bottom	Line	$27.0	$0.7	($0.2)	$26.1	$1.6	$0.7	($0.1)	$0.7	$26.8	997	393
4	Bedington - Black Oak	Interface	$10.0	($13.9)	($1.4)	$22.5	$0.6	$0.7	$0.6	$0.5	$23.0	307	52
5	AP South	Interface	$13.7	($8.1)	($1.5)	$20.2	$0.0	$0.1	($0.0)	($0.1)	$20.1	447	31
6	Yukon	Transformer	($2.6)	($9.7)	$0.3	$7.4	$0.8	$0.8	($0.6)	($0.7)	$6.8	102	58
7	CPL - DOM	Interface	$6.0	($1.1)	$0.8	$7.9	$0.3	$1.6	($0.4)	($1.7)	$6.1	263	98
8	West	Interface	($1.4)	($6.1)	($0.8)	$4.0	$0.0	($0.0)	($0.0)	($0.0)	$4.0	66	11
9	East	Interface	($2.3)	($5.9)	($0.1)	$3.5	($0.0)	$0.0	($0.1)	($0.1)	$3.4	106	2
10	502 Junction	Transformer	($0.3)	($2.9)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	37	0
11	Hunterstown	Transformer	($0.0)	($1.9)	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	169	367
12	Central	Interface	($3.2)	($6.2)	($1.3)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	28	0
13	Keeney - Rockspring	Line	($0.8)	($1.9)	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	158	0
14	Breinigsville - Wescosville	Line	$0.0	($0.2)	$0.4	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	108	0
15	Limerick	Transformer	($0.1)	($0.5)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	103	0
16	Hopatcong - Lackawanna	Line	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.1	$0.1	0	46
17	Wylie Ridge	Transformer	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.1)	($0.1)	0	4
18	Three Mile Island	Transformer	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
19	Valley - Bath County	Line	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
20	Conastone	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
	Top 20 Total		$85.7	($178.9)	($12.8)	$251.8	$17.6	$24.3	$10.2	$3.5	$255.3	3,739	1,259
	All Other Constraints		($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	13	5
	Total		$85.7	($179.0)	($12.8)	$251.8	$17.6	$24.3	$10.2	$3.5	$255.4	3,752	1,264

Table 11-53 Regional constraints summary (By facility): January through September, 2017

			Congestion Costs (Millions)											
			Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	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	$33.2	$2.0	$0.1	$31.4	$1.6	$1.2	$1.6	$2.0	$33.4	2,717	810
2	AP South	Interface	$9.8	($4.6)	($1.3)	$13.1	($0.0)	$1.3	$0.9	($0.5)	$12.6	1,082	75
3	Three Mile Island	Transformer	$5.7	($3.8)	($0.3)	$9.3	($0.0)	($0.4)	$0.9	$1.3	$10.5	417	49
4	Bedington - Black Oak	Interface	$4.1	($2.8)	($0.0)	$6.9	$0.0	$0.2	$0.4	$0.2	$7.1	1,013	56
5	AEP - DOM	Interface	$1.5	($1.6)	$0.1	$3.3	($0.0)	$0.1	($0.3)	($0.4)	$2.8	581	18
6	West	Interface	($0.3)	($1.8)	($0.1)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	163	0
7	5004/5005 Interface	Interface	($0.5)	($1.7)	($0.2)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	65	1
8	Conastone	Transformer	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	33	2
9	Cabot - Keystone	Line	($0.1)	($0.5)	$0.1	$0.5	$0.1	$0.2	($0.0)	($0.2)	$0.3	97	18
10	Belmont	Transformer	($0.0)	($0.2)	($0.1)	$0.1	$0.0	$0.1	($0.3)	($0.4)	($0.3)	42	52
11	East	Interface	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	87	0
12	502 Junction	Transformer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	42	0
13	Bristers - Ox	Line	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
14	Elroy - Hosensack	Line	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
15	Cabot	Other	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
16	Juniata	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	34	0
17	Keeney - Rockspring	Line	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
18	Cunningham - Elmont	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0
19	Wylie Ridge	Transformer	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
20	Valley - Bath County	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
	Top 20 Total		$53.5	($15.9)	($1.6)	$67.8	$1.6	$2.8	$3.2	$2.0	$69.8	6,419	1,081
	All Other Constraints		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	15	1
	Total		$53.5	($15.9)	($1.6)	$67.8	$1.6	$2.8	$3.2	$2.0	$69.8	6,434	1,082

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 $4.4 million in net congestion credits in the first nine months of 2018 and received $16.1 million in net congestion credits in the first nine months of 2017 (Table 11-54 and Table 11-55). Physical entities paid $1,120.6 million in congestion charges in the first nine months of 2018 and $475.1 million in congestion charges in the first nine months of 2017.

Explicit congestion costs are the primary source of congestion credits to financial entities, primarily UTCs. In the first nine months of 2018, the total explicit congestion cost was -$32.9 million, of which -$23.2 million (70.7 percent) was contributed by UTCs. In the first nine months of 2017, the total explicit congestion cost was -$4.4 million, of which -$5.3 million (120.7 percent) was contributed by UTCs.

Table 11-54 Congestion cost by type of participant: January through September, 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$38.6	($3.3)	($41.9)	($0.0)	($23.3)	$3.9	$22.8	($4.4)	$0.0	($4.4)
Physical	$210.4	($928.7)	$12.6	$1,151.7	$41.5	$46.2	($26.4)	($31.1)	$0.0	$1,120.6
Total	$249.0	($931.9)	($29.3)	$1,151.7	$18.2	$50.1	($3.6)	($35.5)	$0.0	$1,116.2

Table 11-55 Congestion cost by type of participant: January through September, 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
Financial	$1.1	$1.2	($6.2)	($6.4)	($7.2)	$4.2	$1.6	($9.8)	$0.0	($16.1)
Physical	$104.0	($376.4)	$8.5	$488.9	$19.6	$28.6	($8.3)	($17.4)	$0.0	$471.5
Total	$105.1	($375.1)	$2.3	$482.5	$12.5	$32.9	($6.7)	($27.1)	$0.0	$455.4

Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.

In 2016, the average hourly UTC submitted MW increased 70.3 percent and UTC cleared MW increased 78.6 percent, compared to 2015.[30] Figure 11-5 shows that day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined and increased after December 7, 2015, when UTC activity increased. Figure 11-5 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined.

In the first nine months of 2018, the average hourly UTC submitted MW decreased by 58.8 percent and UTC cleared MW decreased 48.4 percent, compared to the first nine months of 2017. Day-ahead congestion event hours decreased by 53.0 percent from 224,543 congestion event hours in the first nine months of 2017 to 105,437 congestion event hours in the first nine months of 2018 (Table 11-21). Day-ahead congestion event hours decreased by 65.0 percent from 174,155 congestion event hours for the period February 22, 2017, through September 30, 2017, to 60,917 congestion event hours for the period February 22, 2018 through September 30, 2018.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through September 30, 2018.

30 See *2016 State of the Market Report for PJM*, Vol. 2 Section 3: Energy Market, Table 3-35.

Figure 11-5 Daily congestion event hours: January 2014 through September 2018

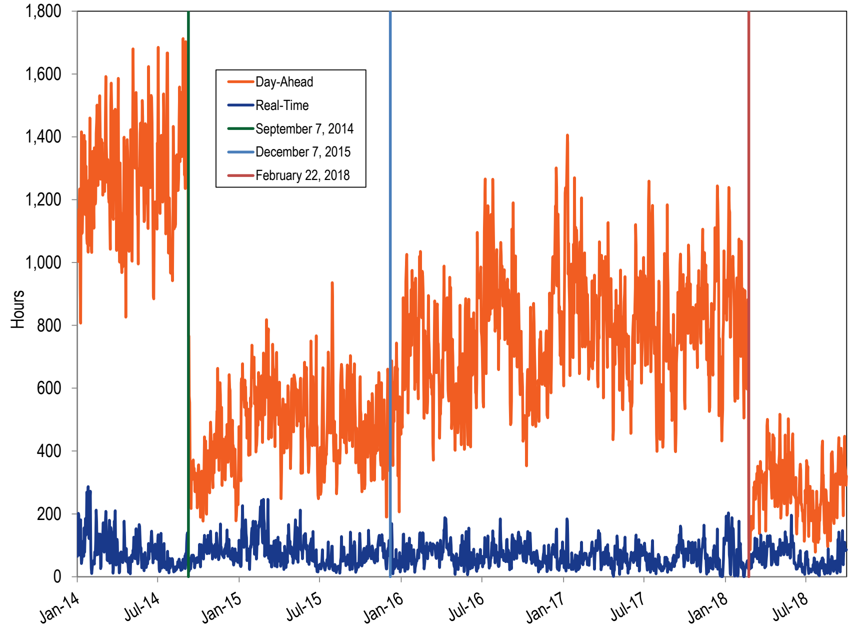


Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: January 2014 through September 2018

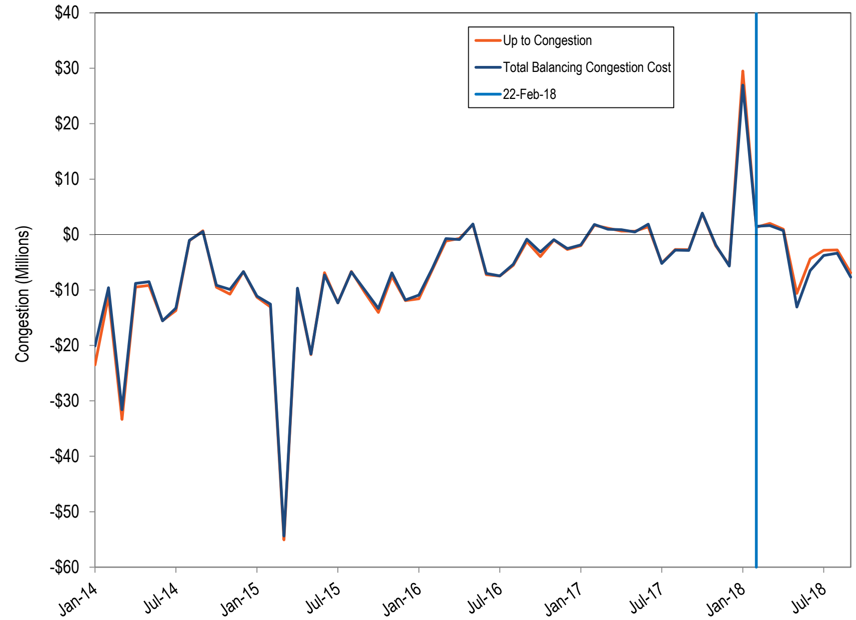


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014 through September 30, 2018. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March of 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January of 2018. Figure 11-6 shows that UTCs are a significant net contributor to balancing congestion in PJM. As shown in Figure 11-6, UTCs are generally paid balancing congestion, which takes the form of negative balancing congestion charges being allocated to UTC positions.

Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative is largely dependent on the nature of the differences that exist between the day-ahead and real-time market models in terms of enforced constraints, transfer capability (line limits) of the enforced constraints, the location of deviations and deviations in flows caused by these modeling differences and the differences in day-ahead and real-time LMPs that result from the interaction between these elements. For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than in the day-ahead market. Due to the complexity of the day-ahead unit commitment process, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have effectively unlimited transfer capability in the day-ahead market model. The reduction in transmission capability between the day-ahead and real-time market between high and low cost generation sources, holding load constant, requires the use of more high cost generation and the use of less low cost generation to serve load. This results in a net increase in generation credits relative to what was incurred in the day-ahead and, holding load constant, no change in load charges. The increase in generation credits relative to load charges causes negative balancing congestion. Negative balancing congestion reduces total congestion collected from the day-ahead position, as the net difference between load charges and generation credits is reduced relative to the day-ahead results.

Due to the nature of the modeling differences between the day-ahead and real-time market, PJM has more system flow capability in the day-ahead market than it does in the real-time market. As a day-ahead spread bid, UTCs are uniquely suited to take advantage of and profit from LMP differences caused by market and transmission modeling differences between the day-ahead and real-time market. UTCs generate flows in the day-ahead market that are not physically possible in the real-time market, clearing between source and sink points with little or no price differences in the day-ahead market, and settling the resulting deviations at higher real-time prices in the real-time market. The general result is negative balancing congestion is caused by and paid to UTCs.

Table 11-56 provides an example of how UTCs can interact with, and profit from, differences in day-ahead and real-time transmission limits and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

Due to the constraint between A and B being effectively unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The prices spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and D. Total day-ahead congestion, which is the difference between congestion charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore generates deviations at Bus A (-200 MW) and at Bus B (+200 MW). The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The reduction in transmission capability between A and B requires a 50 MW reduction in relatively inexpensive $1 generation at A and the use of 50 MW of relatively expensive $6 generation at B. The UTC must settle its deviation MW (-200 MW at A and +200MW at B) at the real time price of $1 at A and $6 at B. The UTC pays $200 to settle its position at A and is paid $1,200 to settle its position at B. The resulting net payment to the UTC is $1,000 in balancing credits.

Table 11-56 shows the balancing credits and charges generated by the real-time deviations by source in the example. Total congestion (day ahead plus balancing congestion) in this example is negative $1,250, with net total congestion credits (payments) to generation and the UTC exceeding the total charges collected from load. The negative balance owed to generation and the UTC is billed to the load as negative balancing congestion.

Due to the modeling differences, the UTC did not contribute to price convergence between the day-ahead and real-time market and did not improve efficiency in system dispatch or commitment. The UTC did significantly increase the cost of energy to the load, with load paying the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet realized load at bus A and bus B.

Table 11-56 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day Ahead Generation	200		0	200
Day Ahead Load	(100)		(100)	(200)
Day Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day Aead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

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.[31] 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.[32] 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

31 OA Schedule 1 §3.7
32 *Id.*

payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

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.[33]

- **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 in a credit. Inadvertent loss charges are

33 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 80 (June 1, 2008) at 70.

common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[34]

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first nine months of 2018 was $757.0 million, which was comprised of load loss payments of -$49.9 million, generation loss credits of -$815.8 million, explicit loss costs of -$8.9 million and inadvertent loss charges of $0.0 million (Table 11-58).

Monthly marginal loss costs in the first nine months of 2018 ranged from $49.5 million in February to $222.8 million in January. Total marginal loss surplus increased in the first nine months of 2018 by $99.9 million or 63.9 percent from $156.5 million in the first nine months of 2017 to $256.4 million in the first nine months of 2018.

Table 11-57 shows the total marginal loss component costs and the total PJM billing for January through September, 2008 through 2018.

Table 11-57 Total PJM loss component costs (Dollars (Millions)): January through September, 2008 through 2018[35]

(Jan - Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,049	NA	$26,979	7.6%
2009	$992	(51.6%)	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,770	3.0%
2015	$830	(33.3%)	$33,710	2.5%
2016	$542	(34.7%)	$29,490	1.8%
2017	$501	(7.5%)	$29,510	1.7%
2018	$757	51.1%	$37,950	2.0%

Table 11-58 shows PJM total marginal loss costs by accounting category for January through September, 2008 through 2018. Table 11-59 shows PJM total marginal loss costs by accounting category by market for January through September, 2008 through 2018.

Table 11-58 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through September, 2008 through 2018

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($210.3)	($2,185.9)	$73.3	$0.0	$2,048.9
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($52.9)	$0.0	$1,243.1
2015	($26.1)	($872.8)	($16.9)	$0.0	$829.8
2016	($41.7)	($605.4)	($21.8)	($0.0)	$541.9
2017	($38.6)	($568.1)	($28.4)	$0.0	$501.0
2018	($49.9)	($815.8)	($8.9)	$0.0	$757.0

34 OA Schedule 1 §3.7.
35 The loss costs include net inadvertent charges.

Table 11-59 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through September, 2008 through 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	($132.3)	($2,133.4)	$100.8	$2,101.8	($77.9)	($52.5)	($27.4)	($52.9)	$0.0	$2,048.9
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1
2015	($47.0)	($883.1)	$24.7	$860.8	$20.9	$10.3	($41.6)	($31.0)	$0.0	$829.8
2016	($48.4)	($606.0)	$37.8	$595.4	$6.6	$0.5	($59.5)	($53.4)	($0.0)	$541.9
2017	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0
2018	($55.7)	($808.1)	$28.6	$780.9	$5.8	($7.8)	($37.5)	($23.9)	$0.0	$757.0

Table 11-60 and Table 11-61 show the total loss costs for each transaction type in the first nine months of 2018 and 2017. In the first nine months of 2018, generation paid loss costs of $763.9 million, 100.9 percent of total loss costs. In the first nine months of 2017, generation paid loss costs of $536.4 million, 107.1 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 the first nine months of 2018, DECs were paid $1.4 million in loss credits in the day-ahead market, paid $1.7 million in congestion costs in the balancing energy market and paid $0.3 million in net payment for losses. In the first nine months of 2018, INCs paid $10.3 million in loss costs in the day-ahead market, were paid $11.3 million in congestion credits in the balancing energy market and were paid $1.0 million in net payment for losses. In the first nine months of 2018, up to congestion paid $29.1 million in loss costs in the day-ahead market, were paid $37.0 million in loss credits in the balancing energy market and received $8.0 million in net payment for losses.

Table 11-60 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2018

	Marginal 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	($1.4)	$0.0	$0.0	($1.4)	$1.7	$0.0	$0.0	$1.7	$0.0	$0.3
Demand	($5.6)	$0.0	$0.0	($5.6)	$10.5	$0.0	$0.0	$10.5	$0.0	$4.8
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Export	($18.0)	$0.0	($0.0)	($18.1)	($6.9)	$0.0	$0.2	($6.7)	$0.0	($24.8)
Generation	$0.0	($764.8)	$0.0	$764.8	$0.0	$0.9	$0.0	($0.9)	$0.0	$763.9
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Import	$0.0	($2.7)	$0.0	$2.7	$0.0	($20.5)	($0.4)	$20.1	$0.0	$22.8
INC	$0.0	($10.3)	$0.0	$10.3	$0.0	$11.3	$0.0	($11.3)	$0.0	($1.0)
Internal Bilateral	($13.5)	($13.1)	$0.4	($0.0)	$0.5	$0.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.1	$29.1	$0.0	$0.0	($37.0)	($37.0)	$0.0	($8.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($38.5)	($790.8)	$28.6	$780.9	$5.8	($7.8)	($37.5)	($23.9)	$0.0	$757.0

Table 11-61 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through September, 2017

	Marginal 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	($7.1)	$0.0	$0.0	($7.1)	$5.6	$0.0	$0.0	$5.6	$0.0	($1.5)
Demand	($4.4)	$0.0	$0.0	($4.4)	$7.7	$0.0	$0.0	$7.7	$0.0	$3.3
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($14.1)	$0.0	$0.1	($14.0)	($7.1)	$0.0	$0.5	($6.6)	$0.0	($20.6)
Generation	$0.0	($535.4)	$0.0	$535.4	$0.0	($1.0)	$0.0	$1.0	$0.0	$536.4
Grandfathered Overuse	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	($0.3)	($0.3)	$0.0	($0.7)
Import	$0.0	($1.4)	$0.0	$1.4	$0.0	($9.3)	($0.2)	$9.1	$0.0	$10.5
INC	$0.0	($11.8)	$0.0	$11.8	$0.0	$10.1	$0.0	($10.1)	$0.0	$1.7
Internal Bilateral	($20.3)	($20.3)	$0.0	($0.0)	$1.0	$1.0	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$42.9	$42.9	$0.0	$0.0	($71.4)	($71.4)	$0.0	($28.5)
Wheel In	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4
Total	($45.9)	($568.9)	$43.1	$566.0	$7.3	$0.8	($71.5)	($65.0)	$0.0	$501.0

Monthly Marginal Loss Costs

Table 11-62 shows a monthly summary of marginal loss costs by market type for January 1, 2017 through September 30, 2018.

Table 11-62 Monthly marginal loss costs by market (Millions): January 2017 through September 2018

	Marginal Loss Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$75.5	($13.2)	($0.0)	$62.3	$227.1	($4.3)	$0.0	$222.8
Feb	$54.2	($7.8)	$0.0	$46.4	$52.7	($3.2)	$0.0	$49.5
Mar	$70.2	($7.4)	$0.0	$62.8	$67.2	$0.0	$0.0	$67.2
Apr	$50.8	($6.6)	$0.0	$44.2	$56.3	($0.9)	$0.0	$55.4
May	$55.0	($4.9)	$0.0	$50.1	$64.5	($1.1)	$0.0	$63.4
Jun	$59.0	($4.2)	$0.0	$54.8	$66.5	($3.4)	($0.0)	$63.2
Jul	$78.7	($7.1)	$0.0	$71.6	$85.7	($3.5)	$0.0	$82.2
Aug	$64.4	($7.6)	$0.0	$56.8	$87.7	($4.6)	$0.0	$83.1
Sep	$58.3	($6.2)	$0.0	$52.0	$73.2	($2.9)	$0.0	$70.2
Oct	$51.8	($4.7)	$0.0	$47.1				
Nov	$55.3	($4.0)	$0.0	$51.3				
Dec	$96.8	($5.3)	$0.0	$91.5				
Total	$769.9	($79.1)	$0.0	$690.8	$780.9	($23.9)	$0.0	$757.0

Figure 11-7 shows PJM monthly marginal loss costs for January 1, 2008 through September 30, 2018.

Figure 11-7 PJM monthly marginal loss costs (Dollars (Millions)): January 2008 through September 2018

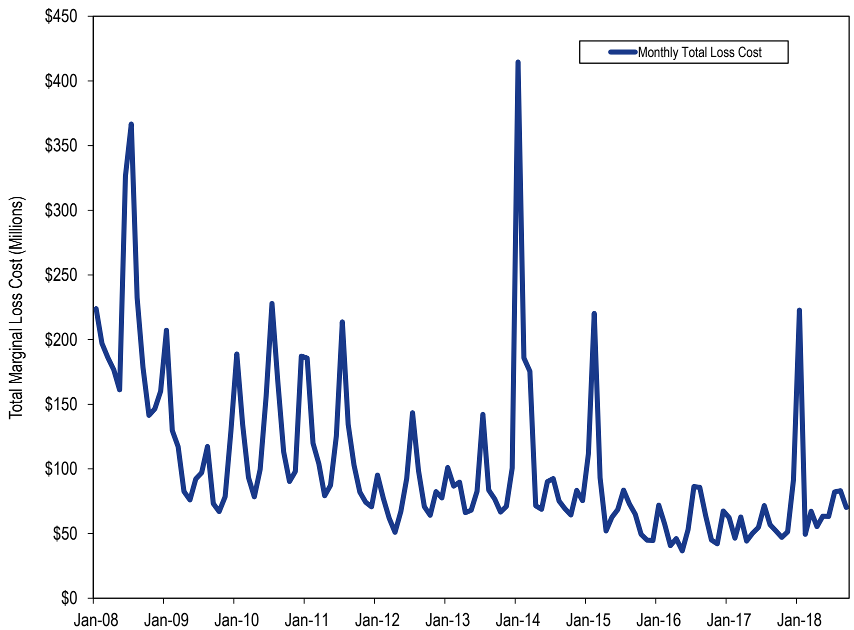


Table 11-63 and Table 11-64 show the monthly total loss costs for each virtual transaction type in the first nine months of 2018 and year of 2017.

Table 11-63 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January through September, 2018

	Marginal Loss Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$0.2	($0.5)	($0.3)	$2.1	($2.4)	($0.2)	$6.6	($8.5)	($1.9)	($2.5)
Feb	($0.2)	$0.0	($0.1)	$0.5	($0.5)	($0.1)	$2.5	($3.9)	($1.4)	($1.6)
Mar	($0.0)	$0.2	$0.2	$1.3	($1.4)	($0.1)	$1.2	($1.5)	($0.3)	($0.2)
Apr	($0.1)	$0.2	$0.1	$1.1	($1.2)	($0.2)	$1.5	($2.1)	($0.6)	($0.7)
May	($0.5)	$0.5	$0.0	$1.1	($1.2)	($0.1)	$2.2	($2.8)	($0.6)	($0.7)
Jun	($0.3)	$0.5	$0.2	$1.1	($1.1)	($0.0)	$3.0	($3.5)	($0.4)	($0.3)
Jul	($0.1)	$0.2	$0.1	$0.8	($0.8)	($0.0)	$3.8	($4.4)	($0.7)	($0.6)
Aug	($0.2)	$0.1	($0.1)	$1.0	($1.1)	($0.1)	$4.4	($5.8)	($1.3)	($1.5)
Sep	($0.3)	$0.5	$0.3	$1.2	($1.4)	($0.1)	$3.8	($4.6)	($0.7)	($0.6)
Total	($1.4)	$1.7	$0.3	$10.3	($11.3)	($1.0)	$29.1	($37.0)	($8.0)	($8.7)

Table 11-64 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Marginal Loss Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	($0.6)	($0.0)	($0.6)	$1.5	($1.3)	$0.2	$6.7	($13.4)	($6.7)	($7.1)
Feb	($0.6)	$0.4	($0.2)	$1.3	($1.1)	$0.2	$5.3	($7.7)	($2.4)	($2.4)
Mar	($1.1)	$0.7	($0.4)	$2.6	($2.0)	$0.6	$5.3	($8.1)	($2.8)	($2.6)
Apr	($1.1)	$1.0	($0.0)	$0.8	($0.9)	($0.1)	$4.5	($6.8)	($2.3)	($2.4)
May	($1.3)	$1.1	($0.2)	$1.6	($1.3)	$0.2	$4.3	($6.4)	($2.1)	($2.1)
Jun	($0.8)	$0.8	($0.0)	$1.1	($0.9)	$0.3	$3.8	($5.8)	($2.0)	($1.7)
Jul	($1.0)	$0.9	($0.1)	$1.4	($0.9)	$0.4	$5.1	($8.0)	($2.9)	($2.7)
Aug	($0.3)	$0.3	($0.0)	$0.6	($0.6)	$0.0	$5.0	($7.8)	($2.8)	($2.8)
Sep	($0.4)	$0.5	$0.1	$1.0	($1.1)	($0.1)	$2.9	($7.4)	($4.5)	($4.5)
Oct	($0.2)	$0.4	$0.1	$0.8	($0.9)	($0.1)	$3.6	($5.9)	($2.2)	($2.2)
Nov	($0.3)	$0.2	($0.0)	$0.7	($0.7)	$0.0	$3.7	($5.4)	($1.6)	($1.6)
Dec	($0.1)	($0.2)	($0.3)	$0.4	($0.3)	$0.1	$4.6	($7.4)	($2.8)	($3.0)
Total	($7.7)	$6.0	($1.7)	$13.8	($12.0)	$1.8	$54.9	($90.0)	($35.1)	($35.1)

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 11-65 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through September, 2008 through 2018. The total marginal loss surplus increased $99.9 million in the first nine months of 2018 from the first nine months of 2017.

Table 11-65 Marginal loss surplus (Dollars (Millions)): January through September, 2008 through 2018[36]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustment			
(Jan - Sep)	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($976.0)	$2,048.9	$0.0	$0.0	$0.0	$1,073.0
2009	($484.6)	$992.4	$0.0	($0.6)	($0.1)	$508.5
2010	($618.6)	$1,259.3	$0.1	$1.3	($0.0)	$639.6
2011	($651.3)	$1,152.6	$0.1	($0.7)	$0.0	$502.1
2012	($442.6)	$757.6	$0.0	$1.7	$0.0	$313.3
2013	($527.2)	$797.0	$0.1	$2.2	($0.0)	$267.6
2014	($833.9)	$1,243.1	($0.0)	$5.1	$0.1	$404.1
2015	($536.5)	$829.8	($0.3)	$4.7	($0.1)	$288.3
2016	($358.3)	$541.9	$0.0	$2.8	($0.2)	$181.0
2017	($344.0)	$501.0	$0.0	$0.7	($0.1)	$156.5
2018	($498.7)	$757.0	($0.0)	$1.9	($0.1)	$256.4

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 the first nine months of 2018 was -$498.7 million, which was comprised of load energy payments of $33,870.5 million, generation energy credits of $34,374.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of $5.7 million. The monthly energy costs for the first nine months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

36 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.

Table 11-66 shows total energy component costs and total PJM billing, for January through September, 2008 through 2018. The total energy component costs are net energy costs.

Table 11-66 Total PJM energy component costs (Dollars (Millions)): January through September, 2008 through 2018[37]

(Jan - Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($976)	NA	$26,979	(3.6%)
2009	($485)	(50.3%)	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,770	(2.0%)
2015	($537)	(35.7%)	$33,710	(1.6%)
2016	($358)	(33.2%)	$29,490	(1.2%)
2017	($344)	(4.0%)	$29,510	(1.2%)
2018	($499)	45.0%	$37,950	(1.3%)

Energy costs for January through September, 2008 through 2018 are shown in Table 11-67 and Table 11-68. Table 11-67 shows PJM energy costs by accounting category and Table 11-68 shows PJM energy costs by market category.

Table 11-67 Total PJM energy costs by accounting category (Dollars (Millions)): January through September, 2008 through 2018

	Energy Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$91,391.9	$92,368.9	$0.0	$1.0	($976.0)
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)
2015	$33,772.7	$34,311.9	$0.0	$2.6	($536.5)
2016	$25,858.3	$26,213.7	$0.0	($2.9)	($358.3)
2017	$26,082.1	$26,430.6	$0.0	$4.5	($344.0)
2018	$33,870.5	$34,374.8	$0.0	$5.7	($498.7)

37 The energy costs include net inadvertent charges.

Table 11-68 Total PJM energy costs by market category (Dollars (Millions)): January through September, 2008 through 2018

Energy Costs (Millions)											
	Day-Ahead				Balancing						
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$67,568.7	$68,653.8	$0.0	($1,085.1)	$23,823.2	$23,715.1	$0.0	$108.1	$1.0	($976.0)
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)
2015	$33,910.7	$34,549.7	$0.0	($639.0)	($138.0)	($237.8)	$0.0	$99.8	$2.6	($536.5)
2016	$25,986.4	$26,469.9	$0.0	($483.5)	($128.1)	($256.2)	$0.0	$128.1	($2.9)	($358.3)
2017	$26,360.1	$26,844.5	$0.0	($484.4)	($278.0)	($413.9)	$0.0	$135.9	$4.5	($344.0)
2018	$33,957.2	$34,508.6	$0.0	($551.4)	($86.7)	($133.8)	$0.0	$47.1	$5.7	($498.7)

Table 11-69 and Table 11-70 show the total energy costs for each transaction type in the first nine months of 2018 and the first nine months of 2017. In the first nine months of 2018, generation was paid $24,187.8 million and demand paid $23,397.1 million in net energy payment. In the first nine months of 2017, generation was paid $18,175.7 million and demand paid $17,363.2 million in net energy payment.

Table 11-69 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through September, 2018

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	$762.2	$0.0	$0.0	$762.2	($777.8)	$0.0	$0.0	($777.8)	($15.6)
Demand	$22,996.9	$0.0	$0.0	$22,996.9	$400.2	$0.0	$0.0	$400.2	$23,397.1
Demand Response	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	$0.0
Export	$639.2	$0.0	$0.0	$639.2	$271.8	$0.0	$0.0	$271.8	$911.0
Generation	$0.0	$24,218.7	$0.0	($24,218.7)	$0.0	($30.9)	$0.0	$30.9	($24,187.8)
Import	$0.0	$105.6	$0.0	($105.6)	$0.0	$504.2	$0.0	($504.2)	($609.7)
INC	$0.0	$624.6	$0.0	($624.6)	$0.0	($625.2)	$0.0	$625.2	$0.6
Internal Bilateral	$9,559.7	$9,559.7	$0.0	$0.0	$11.8	$11.8	$0.0	$0.0	$0.0
Total	$33,957.2	$34,508.6	$0.0	($551.4)	($93.1)	($140.2)	$0.0	$47.1	($504.4)

Table 11-70 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through September, 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	$872.8	$0.0	$0.0	$872.8	($874.9)	$0.0	$0.0	($874.9)	($2.1)
Demand	$17,347.6	$0.0	$0.0	$17,347.6	$15.6	$0.0	$0.0	$15.6	$17,363.2
Demand Response	($0.4)	$0.0	$0.0	($0.4)	$0.4	$0.0	$0.0	$0.4	($0.0)
Export	$533.7	$0.0	$0.0	$533.7	$284.8	$0.0	$0.0	$284.8	$818.6
Generation	$0.0	$18,242.5	$0.0	($18,242.5)	$0.0	($66.8)	$0.0	$66.8	($18,175.7)
Import	$0.0	$60.0	$0.0	($60.0)	$0.0	$285.6	$0.0	($285.6)	($345.6)
INC	$0.0	$935.7	$0.0	($935.7)	$0.0	($928.9)	$0.0	$928.9	($6.9)
Internal Bilateral	$7,606.4	$7,606.4	$0.0	$0.0	$296.0	$296.0	$0.0	($0.0)	($0.0)
Total	$26,360.1	$26,844.6	$0.0	($484.5)	($278.0)	($414.0)	$0.0	$136.0	($348.5)

Monthly Energy Costs

Table 11-71 shows a monthly summary of energy costs by market type for January 1, 2017 through September 30, 2018. Marginal total energy costs in the first nine months of 2018 decreased from the first nine months of 2017. Monthly total energy costs in the first nine months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Table 11-71 Monthly energy costs by market type (Dollars (Millions)): January 2017 through September 2018

	Energy Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($75.6)	$28.9	($1.5)	($48.2)	($160.3)	$4.9	$4.6	($150.9)
Feb	($48.3)	$16.5	$0.0	($31.8)	($41.2)	$7.4	$0.1	($33.6)
Mar	($59.9)	$17.5	$0.2	($42.2)	($45.0)	$2.9	$0.1	($42.1)
Apr	($46.7)	$15.2	$0.5	($31.0)	($40.4)	$2.6	($0.0)	($37.8)
May	($46.2)	$12.6	$1.0	($32.6)	($46.5)	$5.4	$0.3	($40.8)
Jun	($45.8)	$8.6	$0.7	($36.4)	($47.0)	$7.2	($0.1)	($39.9)
Jul	($61.3)	$14.7	$1.2	($45.4)	($59.6)	$5.7	$0.5	($53.5)
Aug	($52.7)	$12.8	$1.1	($38.9)	($60.7)	$5.7	$0.3	($54.6)
Sep	($47.9)	$9.0	$1.3	($37.5)	($50.8)	$5.3	($0.0)	($45.4)
Oct	($43.7)	$8.2	$1.7	($33.8)				
Nov	($45.4)	$9.7	$0.1	($35.5)				
Dec	($75.1)	$12.4	$0.8	($61.9)				
Total	($648.5)	$166.2	$7.1	($475.2)	($551.4)	$47.1	$5.7	($498.7)

Figure 11-8 shows PJM monthly energy costs for January 1, 2008 through September 30, 2018.

Figure 11-8 PJM monthly energy costs (Millions): January 2008 through September 2018

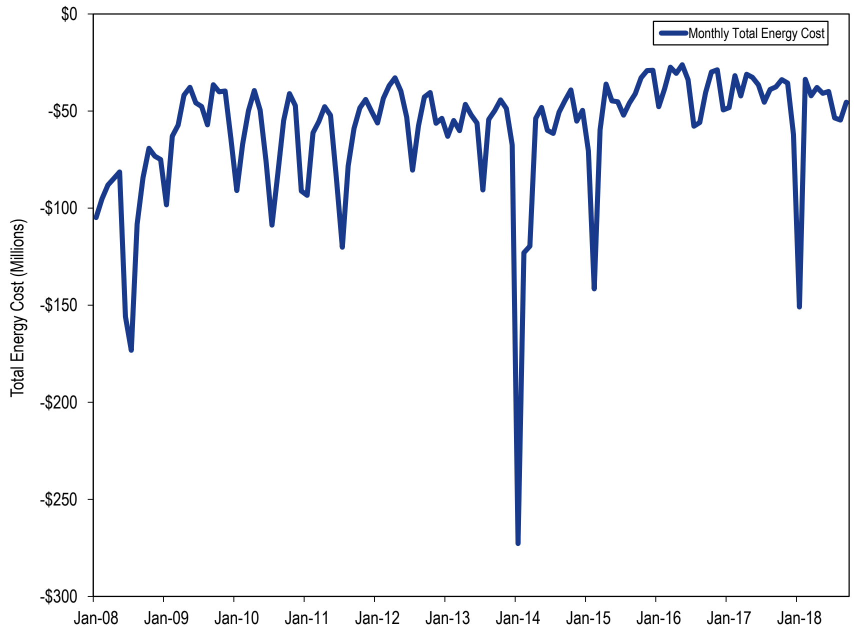


Table 11-72 and Table 11-73 show the monthly total energy costs for each virtual transaction type in the first nine months of 2018 and year of 2017. In the first nine months of 2018, DECs paid $762.2 million in energy costs in the day-ahead market, were paid $777.8 million in energy credits in the balancing energy market and were paid $15.6 million in net payment for energy. In the first nine months of 2018, INCs were paid $624.6 million in energy credits in the day-ahead market, paid $625.2 million in energy costs in the balancing market and paid $0.6 million in energy costs. In the first nine months of 2017, DECs paid $872.8 million in energy costs in the day-ahead market, were paid $874.9 million in energy credits in the balancing energy market and were paid $2.1 million in energy costs. In the first nine months of 2017, INCs were paid $935.7 million in energy credits in the day-ahead market, paid $928.9 million in energy cost in the balancing energy market and received $6.9 million in net payment for energy.

Table 11-72 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January through September, 2018

	Energy Costs (Millions)						
	DEC			INC			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$172.4	($183.2)	($10.8)	($136.9)	$138.3	$1.4	($9.4)
Feb	$47.3	($45.1)	$2.2	($46.3)	$44.2	($2.1)	$0.1
Mar	$65.6	($67.2)	($1.6)	($66.0)	$66.5	$0.4	($1.2)
Apr	$66.2	($67.6)	($1.4)	($76.3)	$76.8	$0.5	($0.9)
May	$86.7	($94.7)	($8.0)	($73.7)	$78.0	$4.3	($3.7)
Jun	$77.1	($74.5)	$2.6	($53.8)	$52.7	($1.0)	$1.6
Jul	$76.5	($71.6)	$4.9	($48.7)	$43.9	($4.7)	$0.2
Aug	$75.8	($75.3)	$0.6	($57.4)	$57.4	($0.0)	$0.6
Sep	$94.5	($98.5)	($4.0)	($65.6)	$67.4	$1.8	($2.2)
Total	$762.2	($777.8)	($15.6)	($624.6)	$625.2	$0.6	($15.0)

Table 11-73 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Energy Costs (Millions)						
	DEC			INC			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$115.3	($116.4)	($1.1)	($134.8)	$135.6	$0.8	($0.3)
Feb	$82.8	($79.8)	$2.9	($107.0)	$103.3	($3.6)	($0.7)
Mar	$123.9	($124.5)	($0.6)	($150.0)	$149.2	($0.8)	($1.4)
Apr	$109.6	($104.2)	$5.4	($106.8)	$102.0	($4.8)	$0.7
May	$112.6	($114.0)	($1.5)	($123.9)	$124.9	$1.0	($0.4)
Jun	$88.3	($87.2)	$1.1	($77.5)	$76.6	($0.9)	$0.2
Jul	$90.2	($93.2)	($2.9)	($92.9)	$95.0	$2.0	($0.9)
Aug	$68.5	($66.9)	$1.6	($70.2)	$68.5	($1.7)	($0.1)
Sep	$81.6	($88.6)	($7.1)	($72.7)	$73.8	$1.1	($6.0)
Oct	$68.6	($66.5)	$2.1	($83.7)	$81.1	($2.6)	($0.5)
Nov	$59.5	($57.0)	$2.5	($75.3)	$72.7	($2.6)	($0.0)
Dec	$91.9	($97.3)	($5.4)	($88.8)	$92.6	$3.8	($1.6)
Total	$1,092.8	($1,095.6)	($2.9)	($1,183.6)	$1,175.3	($8.2)	($11.1)