Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion.[1]

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 (CLMP), and the marginal loss component (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. The relative values of SMP and CLMP are arbitrary and depend on the load-weighted reference bus.

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.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers 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 while generators are paid the price at their bus.

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 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

1 The difference in losses is not part of congestion.

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 for 2018 were calculated as of January 24, 2019, and are subject to change, based on continued PJM billing updates.

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.

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 $612.3 million or 87.8 percent, from $697.6 million in 2017 to $1,309.9 million in 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $645.9 million or 88.1 percent, from $733.1 million in 2017 to $1,378.9 million in 2018.
- **Balancing Congestion.** Negative balancing congestion costs increased by $33.6 million or 94.6 percent, from -$35.5 million in 2017 to -$69.0 million in 2018. Negative balancing explicit costs increased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $667.6 million or 81.7 percent, from $817.5 million in 2017 to $1,485.1 million in 2018.
- **Monthly Congestion.** Monthly total congestion costs in 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 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 55.9 percent from 300,923 congestion event hours in 2017 to 132,598 congestion event hours in 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 2.3 percent from 22,393 congestion event hours in 2017 to 22,910 congestion event hours in 2018.
- **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 2018. With $121.0 million in

4 See the *2018 State of the Market Report for PJM*, Vol. 2, Appendix G "Congestion and Marginal Losses."

5 162 FERC ¶ 61,139.

total congestion costs, it accounted for 9.2 percent of the total PJM congestion costs in 2018.

- **CT Pricing Logic and Closed Loop Interface Related Congestion.** CT pricing logic and closed loop interfaces caused -$1.3 million of day-ahead congestion in 2018 and -$10.2 million of balancing congestion in 2018.
- **Zonal Congestion.** Using the constraint based measure, AEP had the largest zonal congestion costs among all control zones in 2018. AEP had $223.8 million in zonal congestion costs, comprised of $234.9 million in zonal day-ahead congestion costs and -$11.1 million in zonal balancing congestion costs. The AEP - DOM Interface, the Capitol Hill – Chemical Line, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, and the Graceton - Safe Harbor Line contributed $71.4 million, or 31.9 percent of the local AEP control zone congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $269.3 million or 39.0 percent, from $690.8 million in 2017 to $960.1 million in 2018. The loss MWh in PJM increased by 700.3 GWh or 4.7 percent, from 14,920 GWh in 2017 to 15,620 GWh in 2018. The loss component of real-time LMP in 2018 was $0.02, compared to $0.01 in 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 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 $227.3 million or 29.5 percent, from $769.9 million in 2017 to $997.2 million in 2018.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $42.0 million or 53.1 percent, from -$79.1 million in 2017 to -$37.1 million in 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in 2018 by $105.6 million or 49.2 percent, from $214.6 million in 2017, to $320.2 million in 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $161.5 million or 34.0 percent, from -$475.2 million in 2017 to -$636.7 million in 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $62.5 million or 9.6 percent, from -$648.5 million in 2017 to -$711.0 million in 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $96.5 million or 58.1 percent, from $166.2 million in 2017 to $69.7 million in 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in 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 2018 increased significantly from 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 decreased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018. The decrease in balancing explicit congestion costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in May and June of 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 the real-time market but not modeled in the day-ahead market.

The monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018.

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 and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 and, if surplus through December 2018 were distributed, 74.2 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 seven months of 2018/2019 planning periods.

Issues

PJM uses closed loop interfaces and CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM uses a closed loop interface or CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM LMP security constraint pricing logic.

Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource. In the case of a closed loop interface, all buses within the interface are modeled as having a distribution factor (DFAX) of 1.0 to the constraint and therefore have the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affects the CLMP of downstream (constrained side) buses in proportion to their DFAX to that constraint.[6] The objective of making inflexible resources marginal is to minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of closed loop interfaces and CT pricing logic can be a source of modeling differences between the day-ahead and real-time market. If closed loop interfaces and CT pricing logic are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model will result in positive or negative balancing congestion.

The use of the closed loop interface and CT pricing logic makes the inflexible resource marginal in the real-time market. Failure to model the same constraint in the day-ahead market will result in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion. PJM attempts to incorporate its real-time use of closed loop interfaces and CT pricing logic in the day-ahead market, although the matching is necessarily imperfect and with a lag.

Use of closed loop interfaces and CT price setting logic requires the manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic force higher cost inflexible units to be marginal. The resulting constraint specific positive shadow price means a higher price at the unit's bus and at other affected locations.

The result is that more power is produced than consumed in the artificial closed loop. The rest of the system receives power from the closed loop, generators are backed down and prices are lower.

The result is that PJM pays out more to generators in the closed loop than it collects from load. The result of using closed loops and CT price setting logic is negative congestion.

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

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.[7] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] 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 generation 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, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for 2008 through 2018.[9]

The load-weighted average real-time LMP increased $7.25 or 23.4 percent from $30.99 in 2017 to $38.24 in 2018. The load-weighted, average congestion component increased by $0.02 from $0.02 in 2017 to $0.04 in 2018. The load-weighted average loss component in 2018 was $0.02 compared to $0.01 in 2017. The load-weighted, average energy component increased by $7.23 or 23.4 percent from $30.96 in 2017 to $38.19 in 2018.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2008 through 2018[10]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02

7 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>.

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

9 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. Without these adjustments, the congestion component of system average LMP would be zero.

10 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.

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2008 through 2018.[11] The load-weighted average day-ahead LMP increased $7.13, or 23.1 percent, from $30.85 in 2017 to $37.97 in 2018. The load-weighted, average congestion component increased $0.11 from $0.05 in 2017 to $0.16 in 2018. The load-weighted, average loss component increased from -$0.02 in 2017 to -$0.01 in 2018. The load-weighted average energy component increased $7.02, or 22.8 percent, from $30.81 in 2017 to $37.83 in 2018.

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

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)

Table 11-3 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours. In 2018, January had the highest real-time, load-weighted average LMP 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): 2017 and 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	$35.27	$26.11
Nov	$29.43	$23.26	$37.64	$26.58
Dec	$44.60	$24.74	$34.60	$24.19
Avg	$31.81	$24.42	$41.15	$24.71

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for 2017 and 2018. In 2018, BGE had the highest real-time congestion component of all control zones, $3.82, and ComEd had the lowest real-time congestion component, -$5.53.

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

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

	2017				2018			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$29.63	$31.03	($1.86)	$0.46	$37.10	$37.72	($1.45)	$0.83
AEP	$30.17	$30.78	($0.31)	($0.31)	$37.84	$38.20	$0.08	($0.44)
APS	$31.32	$30.92	$0.34	$0.06	$39.83	$38.45	$1.12	$0.25
ATSI	$31.23	$30.70	$0.01	$0.52	$40.24	$37.64	$2.00	$0.60
BGE	$34.76	$31.28	$2.43	$1.06	$44.09	$38.91	$3.82	$1.36
ComEd	$28.29	$30.82	($1.35)	($1.19)	$30.08	$37.45	($5.53)	($1.84)
DAY	$31.06	$30.87	($0.27)	$0.46	$39.00	$38.16	$0.17	$0.67
DEOK	$30.55	$30.91	$0.40	($0.77)	$39.20	$38.14	$1.99	($0.93)
DLCO	$30.63	$30.82	($0.04)	($0.15)	$40.03	$37.72	$2.17	$0.14
Dominion	$33.49	$31.21	$1.90	$0.38	$43.22	$39.09	$3.62	$0.52
DPL	$33.39	$31.35	$1.15	$0.89	$43.82	$39.12	$3.16	$1.54
EKPC	$29.19	$31.34	($1.32)	($0.82)	$36.24	$39.76	($2.31)	($1.21)
JCPL	$30.74	$31.30	($0.94)	$0.38	$37.11	$38.12	($1.66)	$0.65
Met-Ed	$31.15	$30.97	($0.07)	$0.25	$37.10	$38.14	($1.37)	$0.33
OVEC	NA	NA	NA	NA	$30.61	$31.82	($0.27)	($0.94)
PECO	$29.80	$31.04	($1.38)	$0.14	$36.40	$38.15	($2.12)	$0.37
PENELEC	$30.48	$30.60	($0.33)	$0.22	$37.95	$37.74	($0.19)	$0.40
Pepco	$33.70	$31.19	$1.82	$0.69	$42.65	$38.76	$2.98	$0.91
PPL	$29.99	$30.96	($0.99)	$0.02	$35.99	$38.38	($2.37)	($0.02)
PSEG	$30.92	$30.91	($0.37)	$0.38	$36.72	$37.61	($1.48)	$0.59
RECO	$31.26	$31.28	($0.43)	$0.41	$37.43	$37.85	($0.97)	$0.56
PJM	$30.99	$30.96	$0.02	$0.01	$38.24	$38.19	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-5 for 2017 and 2018. In 2018, BGE had the highest day-ahead congestion component of all control zones, $4.23, and ComEd had the lowest day-ahead congestion component, -$5.41.

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

	2017				2018			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$29.14	$30.94	($1.98)	$0.18	$36.74	$37.55	($1.32)	$0.51
AEP	$30.56	$30.75	$0.05	($0.24)	$37.49	$37.90	($0.04)	($0.37)
APS	$31.17	$30.75	$0.42	($0.00)	$39.18	$37.85	$1.12	$0.21
ATSI	$31.23	$30.62	$0.22	$0.39	$39.06	$37.34	$1.18	$0.54
BGE	$34.78	$31.14	$2.72	$0.92	$43.83	$38.41	$4.23	$1.20
ComEd	$28.24	$30.67	($1.59)	($0.84)	$30.15	$37.15	($5.41)	($1.58)
DAY	$31.37	$30.82	$0.01	$0.54	$38.89	$37.79	$0.35	$0.75
DEOK	$31.00	$30.86	$0.66	($0.52)	$40.14	$37.75	$2.97	($0.58)
DLCO	$30.76	$30.74	$0.23	($0.21)	$39.14	$37.48	$1.51	$0.15
Dominion	$33.59	$31.14	$2.04	$0.42	$43.34	$38.73	$4.04	$0.57
DPL	$32.18	$31.22	$0.45	$0.52	$42.53	$38.77	$2.63	$1.12
EKPC	$29.95	$31.32	($0.63)	($0.73)	$36.04	$39.42	($2.29)	($1.09)
JCPL	$29.92	$31.06	($1.29)	$0.15	$36.67	$37.77	($1.47)	$0.37
Met-Ed	$30.44	$30.80	($0.34)	($0.03)	$36.81	$37.65	($0.81)	($0.03)
OVEC	NA	NA	NA	NA	$0.00	$0.00	$0.00	$0.00
PECO	$28.97	$30.76	($1.71)	($0.08)	$35.98	$37.68	($1.76)	$0.06
PENELEC	$29.98	$30.61	($0.65)	$0.02	$37.61	$37.78	($0.42)	$0.25
Pepco	$33.71	$30.95	$2.11	$0.64	$42.65	$38.39	$3.36	$0.91
PPL	$29.30	$30.74	($1.17)	($0.26)	$35.71	$37.82	($1.74)	($0.37)
PSEG	$30.47	$30.86	($0.62)	$0.23	$37.08	$37.59	($0.92)	$0.40
RECO	$30.66	$31.07	($0.66)	$0.25	$37.38	$37.72	($0.72)	$0.38
PJM	$30.85	$30.81	$0.05	($0.02)	$37.97	$37.83	$0.16	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for 2017 and 2018.[12]

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

	2017				2018			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.92	$29.39	($0.38)	($1.09)	$33.06	$35.69	($1.26)	($1.37)
AEP-DAY Hub	$28.81	$29.39	($0.19)	($0.38)	$34.48	$35.69	($0.67)	($0.55)
ATSI Gen Hub	$29.29	$29.39	($0.10)	$0.01	$36.61	$35.69	$1.00	($0.09)
Chicago Gen Hub	$26.31	$29.39	($1.59)	($1.49)	$28.16	$35.69	($5.35)	($2.18)
Chicago Hub	$26.97	$29.39	($1.34)	($1.08)	$28.68	$35.69	($5.33)	($1.68)
Dominion Hub	$31.12	$29.39	$1.55	$0.17	$38.89	$35.69	$3.00	$0.19
Eastern Hub	$30.75	$29.39	$0.65	$0.71	$38.47	$35.69	$1.62	$1.16
N Illinois Hub	$26.69	$29.39	($1.47)	($1.23)	$28.48	$35.69	($5.35)	($1.86)
New Jersey Hub	$28.64	$29.39	($1.02)	$0.27	$34.44	$35.69	($1.74)	$0.49
Ohio Hub	$28.89	$29.39	($0.17)	($0.34)	$34.32	$35.69	($0.82)	($0.55)
West Interface Hub	$29.77	$29.39	$0.57	($0.19)	$37.62	$35.69	$2.20	($0.27)
Western Hub	$29.82	$29.39	$0.37	$0.06	$36.57	$35.69	$0.74	$0.13

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

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

	2017				2018			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$28.36	$29.46	($0.10)	($1.00)	$33.28	$35.57	($1.05)	($1.24)
AEP-DAY Hub	$29.22	$29.46	$0.10	($0.34)	$34.63	$35.57	($0.47)	($0.47)
ATSI Gen Hub	$29.49	$29.46	$0.10	($0.07)	$36.04	$35.57	$0.54	($0.07)
Chicago Gen Hub	$26.33	$29.46	($1.94)	($1.18)	$28.21	$35.57	($5.41)	($1.95)
Chicago Hub	$27.07	$29.46	($1.65)	($0.74)	$28.77	$35.57	($5.38)	($1.43)
Dominion Hub	$31.36	$29.46	$1.68	$0.22	$39.04	$35.57	$3.18	$0.29
Eastern Hub	$30.25	$29.46	$0.34	$0.45	$38.04	$35.57	$1.54	$0.92
N Illinois Hub	$26.82	$29.46	($1.71)	($0.93)	$28.54	$35.57	($5.38)	($1.65)
New Jersey Hub	$28.46	$29.46	($1.11)	$0.12	$34.63	$35.57	($1.24)	$0.30
Ohio Hub	$29.26	$29.46	$0.10	($0.30)	$34.51	$35.57	($0.59)	($0.48)
West Interface Hub	$30.06	$29.46	$0.81	($0.21)	$37.33	$35.57	$1.99	($0.23)
Western Hub	$29.73	$29.46	$0.40	($0.13)	$36.45	$35.57	$0.79	$0.08

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.[13] 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.

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

12 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.

13 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.

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.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. Total congestion costs, when positive, measure the total congestion payment by a participant group and when negative, measure the total congestion credit paid to a participant group. Load congestion payments, when positive, measure the total congestion payment by load and when negative,

14 PJM Operating Agreement Schedule 1 §3.7.

measure the total congestion credit paid by load. Generation congestion credits, when negative, measure the total congestion payment by generation and when positive, measure the total congestion credit paid to generation. 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 accounting definitions can be misleading. Load pays for congestion. Generation does not pay for congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying for congestion.

The CLMP is calculated with respect to the LMP at the system reference bus, 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.[15]

Total Congestion

Total congestion costs in PJM in 2018 were $1,309.9 million, which were comprised of load congestion payments of $360.8 million, generation credits of -$986.5 million and explicit congestion of -$37.4 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy.

Table 11-8 shows total congestion for 2008 through 2018. Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16 17]

Table 11-8 Total PJM congestion component costs (Dollars (Millions)): 2008 through 2018

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%

Table 11-9 shows total congestion by day-ahead and balancing component for 2008 through 2018. Table 11-10 and Table 11-11 show that the decrease in balancing explicit costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in May and June of 2018. The market results were also 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.

15 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>.

16 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>.

17 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 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 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
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in 2018 and 2017. Table 11-10 shows that in 2018 DECs paid $25.3 million in congestion costs in the day-ahead market, were paid $32.7 million in congestion credits in the balancing energy market, resulting in a net payment of $7.4 million in total congestion credits. In 2018, INCs paid $20.5 million in congestion charges in the day-ahead market, were paid $30.0 million in congestion credits in the balancing energy market resulting in a net payment of $9.5 million in total congestion credits. In 2018, up to congestion (UTCs) were paid $19.4 million in congestion credits in the day-ahead market, were paid $7.9 million in congestion credits in the balancing market resulting in a total payment of $27.4 million in total congestion credits.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 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	$25.3	$0.0	$0.0	$25.3	($32.7)	$0.0	$0.0	($32.7)	$0.0	($7.4)
Demand	$101.0	$0.0	$0.0	$101.0	$56.3	$0.0	$0.0	$56.3	$0.0	$157.3
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	$2.2	$2.2	$0.0	$0.0	($0.8)	($0.8)	$0.0	$1.4
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($59.9)	$0.0	($1.0)	($60.9)	($14.7)	$0.0	($5.8)	($20.5)	$0.0	($81.5)
Generation	$0.0	($1,304.8)	$0.0	$1,304.8	$0.0	$70.9	$0.0	($70.9)	$0.0	$1,233.9
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	($6.2)	$0.0	$6.2	$0.0	($41.5)	($3.5)	$38.0	$0.0	$44.2
INC	$0.0	($20.5)	$0.0	$20.5	$0.0	$30.0	$0.0	($30.0)	$0.0	($9.5)
Internal Bilateral	$282.8	$282.8	$0.0	($0.0)	$3.4	$3.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($19.4)	($19.4)	$0.0	$0.0	($7.9)	($7.9)	$0.0	($27.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.5)	$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	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

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

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

Table 11-12 shows the change in total congestion cost incurred by transaction type from 2017 to 2018. Total congestion cost incurred by generation increased by $547.6 million, and total congestion cost incurred by demand increased by $81.4 million. The total congestion payments to up to congestion transactions (UTCs) increased by $7.6 million, from $19.7 million in 2017 to $27.4 million in 2018. Total day-ahead congestion costs payments to UTCs increased by $10.5 million from $8.9 million in 2017 to $19.4 million in 2018. Over the same period balancing congestion costs payments to UTCs decreased by $2.9 million, from $10.8 million in 2017 to $7.9 million in 2018.

Table 11-12 Change in total PJM congestion costs by transaction type by market: 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	$21.0	$0.0	$0.0	$21.0	($15.6)	$0.0	$0.0	($15.6)	$0.0	$5.4
Demand	$65.4	$0.0	$0.0	$65.4	$16.1	$0.0	$0.0	$16.1	$0.0	$81.4
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	$1.2	$1.2	$0.0	$0.0	($0.8)	($0.8)	$0.0	$0.3
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($30.2)	$0.0	($0.5)	($30.7)	($10.3)	$0.0	($7.6)	($17.9)	$0.0	($48.6)
Generation	$0.0	($564.9)	$0.0	$564.9	$0.0	$17.3	$0.0	($17.3)	$0.0	$547.6
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	($4.5)	$0.0	$4.5	$0.0	($31.9)	($2.6)	$29.3	$0.0	$33.8
INC	$0.0	($30.8)	$0.0	$30.8	$0.0	$30.2	$0.0	($30.2)	$0.0	$0.6
Internal Bilateral	$105.4	$105.5	$0.1	$0.0	($0.2)	($0.2)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	($10.5)	($10.5)	$0.0	$0.0	$2.9	$2.9	$0.0	($7.6)
Wheel In	$0.0	$0.1	($0.1)	($0.2)	$0.0	($0.6)	($0.3)	$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	($0.4)
Total	$161.7	($494.5)	($10.4)	$645.9	($10.6)	$14.8	($8.1)	($33.6)	$0.0	$612.3

Zonal Congestion

Area Based Congestion

Area based congestion is the sum of credits and charges for every bus within a specified aggregate of pricing nodes, typically a load zone. 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. This is a less meaningful measure of local congestion than constraint based 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 zonal load. Zonal congestion calculations do not, for example, account for the 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 is the correct method of calculating local congestion. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and 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 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), plus marginal losses (MLMP).

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.

In order to define the load that is actually paying congestion, constraint specific congestion is assigned 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 11-13 shows the area based and constraint based day-ahead and balancing congestion by zone for 2018. Table 11-14 shows the area based and constraint based congestion costs by zone for 2017.

Table 11-13 Area Based and Constraint Based total day ahead and total balancing congestion by zone (Dollars (Millions)): 2018

	Congestion Costs (Millions)					
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	$2.4	($5.4)	($3.0)	$16.9	($0.9)	$16.0
AEP	$358.2	($36.9)	$321.4	$234.9	($11.1)	$223.8
APS	$54.9	($1.1)	$53.8	$79.9	($3.4)	$76.5
ATSI	$96.0	($20.6)	$75.5	$102.9	($5.5)	$97.4
BGE	$57.5	($0.7)	$56.8	$48.1	($2.2)	$45.9
ComEd	$188.9	$45.2	$234.1	$172.3	($9.0)	$163.2
DAY	$16.8	($1.8)	$15.0	$27.9	($1.4)	$26.5
DEOK	$77.2	($10.1)	$67.1	$50.8	($2.1)	$48.7
DLCO	$5.8	$1.6	$7.4	$17.3	($1.1)	$16.2
Dominion	$105.5	($2.9)	$102.5	$158.9	($6.8)	$152.1
DPL	$54.2	($9.5)	$44.7	$87.8	($2.3)	$85.5
EKPC	($17.0)	$4.6	($12.4)	$24.0	($0.7)	$23.4
EXT	($2.2)	($14.4)	($16.6)	$1.4	($5.2)	($3.8)
JCPL	$19.4	($14.4)	$5.0	$39.2	($1.7)	$37.5
Met-Ed	$37.6	($5.7)	$31.8	$31.6	($1.6)	$29.9
OVEC	$0.4	($0.2)	$0.2	($0.0)	$0.0	$0.0
PECO	$103.3	($1.3)	$101.9	$62.4	($2.8)	$59.6
PENELEC	$75.4	($2.6)	$72.8	$32.1	($2.2)	$29.9
Pepco	$47.8	$3.8	$51.5	$44.6	($1.9)	$42.6
PPL	$45.1	$11.2	$56.3	$69.9	($2.6)	$67.3
PSEG	$52.7	($6.5)	$46.2	$73.4	($4.0)	$69.4
RECO	($1.2)	($1.0)	($2.2)	$2.6	($0.5)	$2.0
Total	$1,378.9	($69.0)	$1,309.9	$1,378.9	($69.0)	$1,309.9

Table 11-14 Area based and constraint based total day ahead and total balancing congestion by zone (Dollars (Millions)): 2017

	Congestion Costs (Millions)					
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	($2.3)	($1.4)	($3.7)	$9.3	($0.6)	$8.7
AEP	$91.5	($9.6)	$81.8	$116.4	($7.5)	$108.9
APS	$20.7	($0.4)	$20.3	$31.1	($3.3)	$27.8
ATSI	$26.8	($7.2)	$19.5	$43.7	($4.2)	$39.5
BGE	$42.4	($2.5)	$39.9	$26.6	($1.9)	$24.7
ComEd	$231.9	($3.7)	$228.2	$161.8	($4.9)	$156.9
DAY	($1.4)	$1.5	$0.1	$12.2	($0.9)	$11.3
DEOK	$13.9	$5.1	$18.9	$21.8	($1.1)	$20.7
DLCO	$0.8	($1.4)	($0.6)	$7.6	($0.7)	$6.9
Dominion	$63.7	($10.0)	$53.7	$73.7	($6.3)	$67.3
DPL	($7.6)	$14.5	$6.9	$22.2	$13.0	$35.2
EKPC	($6.2)	$2.7	($3.6)	$10.6	($0.7)	$9.9
EXT	($10.1)	($14.7)	($24.8)	($1.9)	($2.5)	($4.4)
JCPL	$6.7	$0.8	$7.6	$21.2	($1.5)	$19.7
Met-Ed	$18.1	$1.5	$19.6	$16.5	($1.5)	$15.0
PECO	$79.5	($4.4)	$75.2	$36.3	($2.7)	$33.7
PENELEC	$57.8	($7.6)	$50.2	$16.2	($1.6)	$14.6
Pepco	$32.9	$6.2	$39.1	$24.2	($1.7)	$22.5
PPL	$28.8	$4.4	$33.3	$39.8	($2.2)	$37.5
PSEG	$46.2	($9.5)	$36.7	$42.2	($2.5)	$39.8
RECO	($1.1)	$0.1	($0.9)	$1.5	($0.1)	$1.4
Total	$733.1	($35.5)	$697.6	$733.1	($35.5)	$697.6

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In these special cases the associated congestion is assigned to the control zone or residual load aggregate where the congestion is incurred and/or there are positive CLMPs from that constraint. Table 11-13 and Table 11-14 include congestion allocations from these special case constraints.

There are four basic categories of constraint specific allocation special cases: congestion associated with constraints with no downstream load bus (no load bus); congestion associated with constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interface and CT price setting logic (closed loop and CT price setting logic) and congestion associated with nontransmission facility constraints in the Day-Ahead Energy Market and/or any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors (unclassified).

Table 11-15 and Table 11-16 break out the allocation of total congestion by each special case allocation method, congestion allocated by the standard method (allocation) and total allocation (total) by zone.

Table 11-15 and Table 11-16 show that closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource.

Table 11-15 Constraint based total day-ahead and total balancing congestion by zone and special case logic (Dollars (Millions)): 2018

	Congestion Costs (Millions)												
	Day-Ahead						Balancing						
Control Zone	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.1	$0.3	$0.0	$16.4	$16.9	$0.0	($0.0)	$0.0	($0.0)	($0.8)	($0.9)	$16.0
AEP	$0.3	$0.0	$0.5	($0.0)	$234.1	$234.9	$0.0	($2.3)	($0.0)	$0.2	($9.0)	($11.1)	$223.8
APS	$0.0	($0.3)	$0.0	($0.0)	$80.2	$79.9	$0.0	($0.1)	$0.0	($0.0)	($3.3)	($3.4)	$76.5
ATSI	$0.0	$0.5	$0.2	$0.0	$102.2	$102.9	$0.0	($0.2)	$0.0	($0.0)	($5.3)	($5.5)	$97.4
BGE	$0.0	($0.0)	$0.0	$0.0	$48.1	$48.1	$0.0	($0.1)	($0.0)	($0.0)	($2.1)	($2.2)	$45.9
ComEd	$1.4	($1.0)	$7.4	($0.0)	$164.4	$172.3	($0.0)	($2.1)	$0.2	$0.3	($7.5)	($9.0)	$163.2
DAY	$0.0	$0.1	$0.0	$0.0	$27.8	$27.9	$0.0	($0.2)	$0.0	$0.2	($1.4)	($1.4)	$26.5
DEOK	$0.2	$0.2	$2.0	$0.0	$48.5	$50.8	$0.0	$0.0	$0.0	$0.1	($2.2)	($2.1)	$48.7
DLCO	$0.0	$0.0	$0.0	($0.0)	$17.3	$17.3	$0.0	($0.0)	$0.0	$0.0	($1.1)	($1.1)	$16.2
Dominion	$0.0	$0.2	$0.4	$0.0	$158.3	$158.9	$0.0	($0.0)	($0.0)	($0.0)	($6.7)	($6.8)	$152.1
DPL	$0.1	$0.5	$0.4	$0.0	$86.8	$87.8	$0.0	($0.1)	$0.0	($0.1)	($2.1)	($2.3)	$85.5
EKPC	$0.0	($0.0)	$0.0	$0.0	$24.0	$24.0	$0.0	$0.1	$0.0	$0.1	($0.8)	($0.7)	$23.4
EXT	$0.0	$0.1	$0.9	$0.4	$0.0	$1.4	$0.0	($4.0)	($0.0)	($1.1)	$0.0	($5.2)	($3.8)
JCPL	$0.0	$0.7	$0.0	$0.0	$38.5	$39.2	$0.0	($0.1)	$0.0	($0.0)	($1.6)	($1.7)	$37.5
Met-Ed	$0.0	$0.2	$3.1	$0.0	$28.3	$31.6	($0.0)	($0.0)	($0.5)	$0.0	($1.1)	($1.6)	$29.9
OVEC	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0
PECO	$0.0	($0.6)	$0.4	($0.0)	$62.6	$62.4	($0.0)	($0.1)	$0.0	$0.0	($2.7)	($2.8)	$59.6
PENELEC	$0.3	$0.1	$0.8	($0.0)	$30.8	$32.1	$0.0	$0.1	$0.0	$0.1	($2.4)	($2.2)	$29.9
Pepco	$0.0	$0.1	$0.0	$0.0	$44.5	$44.6	$0.0	$0.1	$0.0	($0.0)	($2.1)	($1.9)	$42.6
PPL	$0.1	($2.0)	$1.0	($0.0)	$70.8	$69.9	$0.0	$0.1	$0.0	$0.0	($2.7)	($2.6)	$67.3
PSEG	$0.0	($0.2)	$1.0	($0.0)	$72.6	$73.4	$0.0	($0.7)	$0.0	($0.0)	($3.3)	($4.0)	$69.4
RECO	$0.0	($0.1)	$0.0	$0.0	$2.6	$2.6	$0.0	($0.4)	$0.0	$0.0	($0.1)	($0.5)	$2.0
Total	$2.4	($1.3)	$18.5	$0.4	$1,358.8	$1,378.9	($0.0)	($10.2)	($0.3)	($0.4)	($58.2)	($69.0)	$1,309.9

Table 11-16 Constraint Based total day-ahead and total balancing congestion by zone and special case logic (Dollars (Millions)): 2017

	Congestion Costs (Millions)												
	Day-Ahead						Balancing						
Control Zone	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	$0.0	$0.3	$0.2	($0.0)	$8.9	$9.3	($0.0)	($0.0)	$0.0	$0.0	($0.6)	($0.6)	$8.7
AEP	$0.7	$0.9	$3.6	($0.0)	$111.2	$116.4	$0.0	($0.5)	($0.5)	$0.1	($6.6)	($7.5)	$108.9
APS	$0.0	($0.5)	$0.2	$0.0	$31.4	$31.1	$0.0	($0.2)	($0.4)	$0.0	($2.7)	($3.3)	$27.8
ATSI	$0.0	$1.0	$0.0	$0.0	$42.6	$43.7	$0.0	($0.7)	$0.0	$0.0	($3.5)	($4.2)	$39.5
BGE	$0.0	$0.5	($0.0)	$0.0	$26.1	$26.6	$0.0	($0.0)	$0.0	$0.0	($1.9)	($1.9)	$24.7
ComEd	$1.4	($1.3)	$11.3	($0.0)	$150.3	$161.8	($0.0)	$0.4	$0.2	$0.5	($6.0)	($4.9)	$156.9
DAY	($0.0)	$0.0	$0.0	$0.0	$12.2	$12.2	$0.0	$0.0	$0.0	$0.0	($0.9)	($0.9)	$11.3
DEOK	$0.1	($0.2)	$1.9	$0.0	$20.0	$21.8	$0.0	$0.2	($0.0)	$0.0	($1.4)	($1.1)	$20.7
DLCO	$0.0	($0.1)	$0.0	($0.0)	$7.6	$7.6	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	$6.9
Dominion	$0.0	$0.6	$0.1	$0.0	$72.9	$73.7	$0.0	($0.1)	$0.0	$0.0	($6.3)	($6.3)	$67.3
DPL	$0.1	($16.9)	$0.1	$0.0	$39.0	$22.2	($0.0)	$0.1	($0.0)	$0.0	$12.9	$13.0	$35.2
EKPC	$0.0	$0.0	$0.0	$0.0	$10.6	$10.6	$0.0	($0.0)	($0.0)	($0.0)	($0.7)	($0.7)	$9.9
EXT	($0.0)	($1.8)	($0.2)	$0.2	$0.0	($1.9)	$0.0	($0.9)	($0.0)	($1.6)	$0.0	($2.5)	($4.4)
JCPL	$0.0	$0.2	$0.0	$0.0	$21.0	$21.2	($0.0)	$0.0	$0.0	($0.1)	($1.4)	($1.5)	$19.7
Met-Ed	$0.1	($0.7)	$0.2	($0.0)	$17.0	$16.5	$0.0	($0.0)	$0.0	($0.0)	($1.5)	($1.5)	$15.0
PECO	$0.2	($2.1)	$0.8	($0.0)	$37.4	$36.3	$0.0	$0.0	$0.0	($0.0)	($2.7)	($2.7)	$33.7
PENELEC	$0.8	($2.1)	$1.2	($0.0)	$16.3	$16.2	$0.0	($0.7)	$0.0	$0.1	($1.0)	($1.6)	$14.6
Pepco	$0.0	$0.6	($0.0)	$0.0	$23.6	$24.2	$0.0	$0.0	$0.0	$0.0	($1.7)	($1.7)	$22.5
PPL	$0.3	($1.6)	$4.4	($0.0)	$36.7	$39.8	$0.0	($0.0)	$0.3	$0.0	($2.5)	($2.2)	$37.5
PSEG	$0.1	$0.0	$0.2	($0.0)	$42.0	$42.2	$0.0	($0.0)	$0.0	$0.2	($2.6)	($2.5)	$39.8
RECO	$0.0	($0.0)	$0.0	$0.0	$1.5	$1.5	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	$1.4
Total	$3.8	($23.2)	$23.9	$0.2	$728.4	$733.1	$0.0	($2.4)	($0.4)	($0.8)	($31.8)	($35.5)	$697.6

Monthly Congestion

Table 11-17 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, were 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. Higher negative generation credits mean that generation was paid less and that the difference between load payments and generator credits (the difference is congestion) was therefore higher.

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 11-17 Monthly PJM congestion costs by market (Dollars (Millions)): 2017 and 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	$95.0	($11.8)	($0.0)	$83.3
Nov	$59.9	($1.5)	($0.0)	$58.3	$69.1	($14.2)	($0.0)	$54.9
Dec	$139.8	($18.1)	($0.0)	$121.7	$63.0	($7.6)	$0.0	$55.5
Total	$733.1	($35.5)	$0.0	$697.6	$1,378.9	($69.0)	$0.0	$1,309.9

Figure 11-1 shows PJM monthly total congestion cost for 2008 through 2018.

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

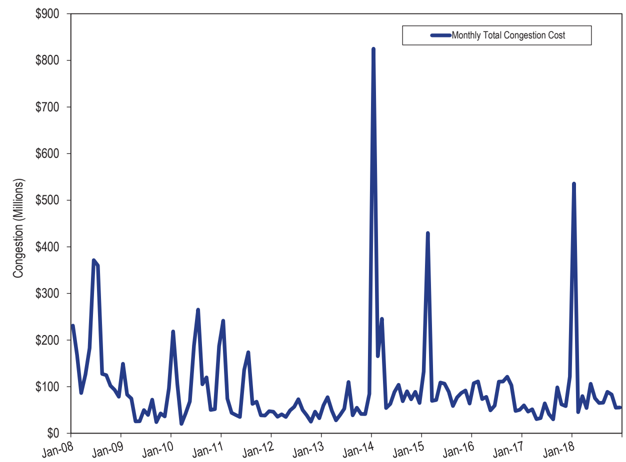


Table 11-18 and Table 11-19 show monthly total congestion costs for each virtual transaction type in 2018 and 2017. Virtual transaction congestion costs, when positive, are the total congestion cost (charge) to the virtual transaction and when negative, are the total congestion credit (payment) to the virtual transaction. The negative totals in Table 11-18 and Table 11-19 show that virtuals were paid in 2018 and in 2017. More than half the total payment to virtuals went to UTCs.

Table 11-18 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 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)
Oct	$1.5	($2.6)	($1.1)	$2.4	($3.2)	($0.8)	$2.5	($3.3)	($0.8)	($2.7)
Nov	$2.1	($3.3)	($1.2)	$0.4	($2.3)	($1.9)	$4.3	($7.5)	($3.2)	($6.3)
Dec	$3.7	($3.5)	$0.1	($1.2)	$2.0	$0.8	$3.4	($3.5)	($0.1)	$0.8
Total	$25.3	($32.7)	($7.4)	$20.5	($30.0)	($9.5)	($19.4)	($7.9)	($27.4)	($44.3)

Table 11-19 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 2018, there were 132,598 day-ahead, congestion event hours compared to 300,923 day-ahead congestion event hours in 2017. Of the 2018 day-ahead congestion event hours, only 9,965 (7.5 percent) were also constrained in the Real-Time Energy Market. In 2018, there were 22,910 real-time, congestion event hours compared to 22,393 real-time, congestion event hours in 2017. Of 2018 real-time congestion event hours, 10,071 (44.0 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $375.6 million, or 28.7 percent, of the total PJM congestion costs in 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 10 constraints between 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 (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.[18] The order limited UTC trading to hubs, residual metered load, and interfaces.

Real-time, congestion event hours increased on lines and decreased on flowgates, interfaces and transformers. The increase on lines was primarily a result of the increase on lines in the AEP and BGE control zones. 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 2018.

Day-ahead congestion costs increased on all types of facilities in 2018 compared to 2017. Day-ahead generation credits decreased on all types of facilities in 2018 compared to 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 interfaces and transformers and decreased on flowgates and lines in 2018 compared to 2017. Table 11-20 provides congestion event hour subtotals and congestion cost subtotals comparing 2018 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19 20]

Table 11-21 presents this information for 2017.

Table 11-20 Congestion summary (By facility type): 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	($56.0)	($338.9)	($36.4)	$246.4	$2.0	$7.3	($2.9)	($8.2)	$238.2	19,816	5,585
Interface	$65.0	($163.6)	($13.9)	$214.6	$15.2	$22.8	$11.1	$3.6	$218.2	2,316	397
Line	$257.2	($387.1)	$28.1	$672.4	($10.1)	$29.3	($25.6)	($65.0)	$607.4	78,963	14,310
Transformer	$64.4	($141.4)	$1.7	$207.5	$0.4	$2.9	$4.0	$1.5	$209.0	26,714	1,568
Other	$18.6	($17.5)	$1.5	$37.6	$3.0	($1.0)	($4.4)	($0.4)	$37.1	4,789	1,050
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

18 162 FERC ¶ 61,139.

19 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.

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

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

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($52.9)	($207.3)	($24.6)	$129.8	$7.2	$6.0	($3.3)	($2.1)	$127.7	29,579	5,969
Interface	$16.0	($58.8)	($7.0)	$67.8	$5.1	$14.2	$5.7	($3.4)	$64.4	4,635	441
Line	$186.3	($233.0)	$12.6	$431.9	$5.3	$20.5	($0.1)	($15.2)	$416.7	155,443	12,961
Transformer	$33.2	($48.7)	$9.4	$91.3	$3.8	$4.0	($13.9)	($14.1)	$77.2	94,643	2,493
Other	$4.9	($6.2)	$1.0	$12.1	$0.6	$1.3	$0.9	$0.2	$12.3	16,623	529
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.2	$1.2	$0.2	($0.8)	($0.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,393

Table 11-22 and Table 11-23 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 11-22. In 2018, there were 132,598 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 9,965 (7.5 percent) were also constrained in the Real-Time Energy Market. There were 88,078 congestion event hours in the Day-Ahead Energy Market for the period February 22, 2018 through December 31, 2018. Of those day-ahead congestion event hours, only 8,060 (9.2 percent) were also constrained in the Real-Time Energy Market. In 2017, of the 300,923 day-ahead congestion event hours, only 11,961 (4.0 percent) were binding in the Real-Time Energy Market.[21]

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 11-23. In 2018, of the 22,910 congestion event hours in the Real-Time Energy Market, 10,071 (44.0 percent) were also constrained in the Day-Ahead Energy Market. In 2017, of the 22,393 real-time congestion event hours, 11,733 (52.4 percent) were also in the Day-Ahead Energy Market.

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

	Congestion Event Hours					
	2017			2018		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	29,579	2,464	8.3%	19,816	2,017	10.2%
Interface	4,635	268	5.8%	2,316	239	10.3%
Line	155,443	7,972	5.1%	78,963	6,504	8.2%
Transformer	94,643	968	1.0%	26,714	702	2.6%
Other	16,623	289	1.7%	4,789	503	10.5%
Total	300,923	11,961	4.0%	132,598	9,965	7.5%

Table 11-23 Congestion event hours (real-time against day-ahead): 2017 and 2018

	Congestion Event Hours					
	2017			2018		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	5,969	2,473	41.4%	5,585	2,019	36.2%
Interface	441	333	75.5%	397	264	66.5%
Line	12,961	7,722	59.6%	14,310	6,566	45.9%
Transformer	2,493	916	36.7%	1,568	708	45.2%
Other	529	289	54.6%	1,050	514	49.0%
Total	22,393	11,733	52.4%	22,910	10,071	44.0%

21 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 11-24 shows congestion costs by facility voltage class for 2018. Congestion costs in 2018 increased for all facilities except 34 kV or 18 kV facilities compared to 2017, caused by the large increase in day-ahead congestion costs in January 2018 (Table 11-25).

Table 11-24 Congestion summary (By facility voltage): 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	$0.5	($1.6)	$0.2	$2.3	$0.7	$0.3	($0.0)	$0.4	$2.6	106	21
500	$89.2	($183.2)	($13.6)	$258.7	$16.6	$21.2	$11.5	$6.9	$265.6	3,951	994
345	$12.2	($271.6)	$1.1	$284.9	$0.3	($0.9)	($12.6)	($11.5)	$273.4	20,762	2,785
230	$182.3	($70.1)	$4.5	$256.9	($1.2)	$7.7	($1.2)	($10.1)	$246.8	22,259	5,686
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$1.4	($4.4)	($0.5)	$5.3	$0.3	($0.4)	$0.5	$1.1	$6.4	356	85
138	($2.2)	($455.0)	($14.0)	$438.8	$2.8	$26.3	($10.0)	($33.5)	$405.3	50,411	9,324
115	$7.3	($71.7)	($3.1)	$75.9	($0.7)	$3.7	$0.4	($4.0)	$71.9	14,078	1,996
69	$58.2	$9.6	$6.1	$54.7	($8.2)	$3.4	($6.4)	($17.9)	$36.7	17,281	1,958
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.1	$0.0	($0.0)	$0.4	2,127	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	291	0
12	$0.0	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	569	0
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

Table 11-25 Congestion summary (By facility voltage): 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.2)	$0.8	$2.6	($0.2)	$0.0	$0.0	($0.2)	$2.4	1,070	35
500	$74.5	($70.2)	($5.7)	$138.9	$7.9	$17.3	$8.8	($0.6)	$138.4	9,061	1,535
345	($11.0)	($140.4)	$1.0	$130.4	$8.4	$9.4	($16.9)	($17.9)	$112.5	59,380	3,219
230	$121.0	($47.5)	$1.6	$170.1	$6.8	$18.9	($1.7)	($13.8)	$156.3	47,474	5,750
161	($0.0)	($0.3)	($0.0)	$0.3	$0.1	($0.0)	$0.1	$0.2	$0.4	33	34
138	($10.6)	($266.5)	($4.1)	$251.8	$4.3	$13.3	($5.0)	($13.9)	$237.9	128,573	8,787
115	$3.7	($34.5)	$0.1	$38.2	($0.7)	$2.2	$1.3	($1.6)	$36.6	30,626	1,913
69	$9.1	$7.2	($2.7)	($0.9)	($4.6)	($15.1)	$2.7	$13.2	$12.4	17,329	1,120
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
34	$0.3	$0.0	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	5,573	0
18	($0.0)	($0.6)	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,677	0
17	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	101	0
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.2	$1.2	$0.2	($0.8)	($0.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,393

Constraint Duration

Table 11-26 lists the constraints for 2017 and 2018 that were most frequently binding and Table 11-27 shows the constraints which experienced the largest change in congestion event hours from 2017 to 2018. In Table 11-26, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 2018. In Table 11-27, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2017 to 2018.

Table 11-26 Top 25 constraints with frequent occurrence: 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Graceton - Safe Harbor	Line	3,118	3,361	243	1,151	2,046	895	36%	38%	3%	13%	23%	10%
2	Easton - Emuni	Line	1,987	3,831	1,844	1	2	1	23%	44%	21%	0%	0%	0%
3	Monroe - Vineland	Line	343	2,858	2,515	13	500	487	4%	33%	29%	0%	6%	6%
4	Gardners - Texas East	Line	1,317	2,788	1,471	116	439	323	15%	32%	17%	1%	5%	4%
5	Quad Cities	Trf	9,457	2,614	(6,843)	0	0	0	108%	30%	(78%)	0%	0%	0%
6	Emilie - Falls	Line	5,171	1,593	(3,578)	894	329	(565)	59%	18%	(41%)	10%	4%	(6%)
7	Fargo	Flowgate	0	1,308	1,308	0	510	510	0%	15%	15%	0%	6%	6%
8	Newton	Flowgate	789	1,283	494	173	426	253	9%	15%	6%	2%	5%	3%
9	Lakeview - Greenfield	Line	1,593	1,356	(237)	164	352	188	18%	15%	(3%)	2%	4%	2%
10	Roxana - Praxair	Flowgate	1,734	1,132	(602)	290	481	191	20%	13%	(7%)	3%	5%	2%
11	North Salisbury - Rockawalkin	Line	0	1,610	1,610	0	0	0	0%	18%	18%	0%	0%	0%
12	Nottingham	Other	1,065	1,157	92	316	390	74	12%	13%	1%	4%	4%	1%
13	Conastone - Peach Bottom	Line	3,159	1,100	(2,059)	840	422	(418)	36%	13%	(24%)	10%	5%	(5%)
14	Quad Cities - Cordova	Flowgate	514	1,522	1,008	0	0	0	6%	17%	12%	0%	0%	0%
15	Tanners Creek - Miami Fort	Flowgate	74	1,511	1,437	0	0	0	1%	17%	16%	0%	0%	0%
16	Brokaw - Leroy	Flowgate	1,744	1,232	(512)	528	261	(267)	20%	14%	(6%)	6%	3%	(3%)
17	Delaware - Hogan	Line	1	1,227	1,226	0	235	235	0%	14%	14%	0%	3%	3%
18	Cedar Grove Sub - Roseland	Line	355	1,368	1,013	54	64	10	4%	16%	12%	1%	1%	0%
19	Berwick - Koonsville	Line	574	1,425	851	12	6	(6)	7%	16%	10%	0%	0%	(0%)
20	Olive	Other	6,460	1,327	(5,133)	0	0	0	74%	15%	(59%)	0%	0%	0%
21	Flint Lake - Luchtman Road	Flowgate	0	890	890	0	365	365	0%	10%	10%	0%	4%	4%
22	Zion	Line	4,644	1,193	(3,451)	0	0	0	53%	14%	(39%)	0%	0%	0%
23	Sayreville - Sayreville	Line	675	1,192	517	0	0	0	8%	14%	6%	0%	0%	0%
24	Tanners Creek - Miami Fort	Line	1,213	673	(540)	63	489	426	14%	8%	(6%)	1%	6%	5%
25	Maple - Jackson	Line	134	1,000	866	5	155	150	2%	11%	10%	0%	2%	2%

Table 11-27 Top 25 constraints with largest year to year change in occurrence: 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Quad Cities	Trf	9,457	2,614	(6,843)	0	0	0	108%	30%	(78%)	0%	0%	0%
2	Olive	Other	6,460	1,327	(5,133)	0	0	0	74%	15%	(59%)	0%	0%	0%
3	Waukegan	Trf	5,226	1,083	(4,143)	0	0	0	60%	12%	(47%)	0%	0%	0%
4	Emilie - Falls	Line	5,171	1,593	(3,578)	894	329	(565)	59%	18%	(41%)	10%	4%	(6%)
5	Braidwood - East Frankfort	Line	4,171	203	(3,968)	301	144	(157)	48%	2%	(45%)	3%	2%	(2%)
6	East Bend	Trf	4,464	453	(4,011)	0	0	0	51%	5%	(46%)	0%	0%	0%
7	Hinchmans	Trf	4,378	773	(3,605)	0	0	0	50%	9%	(41%)	0%	0%	0%
8	Westwood	Flowgate	3,399	0	(3,399)	198	0	(198)	39%	0%	(39%)	2%	0%	(2%)
9	Zion	Line	4,644	1,193	(3,451)	0	0	0	53%	14%	(39%)	0%	0%	0%
10	Seneca	Trf	3,399	299	(3,100)	0	0	0	39%	3%	(35%)	0%	0%	0%
11	Loretto - Vienna	Line	3,950	936	(3,014)	60	5	(55)	45%	11%	(34%)	1%	0%	(1%)
12	Tanners Creek	Trf	3,461	402	(3,059)	0	0	0	40%	5%	(35%)	0%	0%	0%
13	Howard - Shelby	Line	3,041	0	(3,041)	0	0	0	35%	0%	(35%)	0%	0%	0%
14	Monroe - Vineland	Line	343	2,858	2,515	13	500	487	4%	33%	29%	0%	6%	6%
15	West Chicago	Trf	3,490	606	(2,884)	0	0	0	40%	7%	(33%)	0%	0%	0%
16	Saddlebrook	Trf	3,098	322	(2,776)	0	0	0	35%	4%	(32%)	0%	0%	0%
17	Cherry Valley	Trf	3,007	403	(2,604)	149	3	(146)	34%	5%	(30%)	2%	0%	(2%)
18	Elwood	Other	2,571	0	(2,571)	0	0	0	29%	0%	(29%)	0%	0%	0%
19	Conastone - Peach Bottom	Line	3,159	1,100	(2,059)	840	422	(418)	36%	13%	(24%)	10%	5%	(5%)
20	Electric Junction	Trf	2,914	436	(2,478)	0	2	2	33%	5%	(28%)	0%	0%	0%
21	Liquid Carbonics	Trf	2,586	147	(2,439)	0	0	0	30%	2%	(28%)	0%	0%	0%
22	Gould Street - Westport	Line	2,800	417	(2,383)	0	8	8	32%	5%	(27%)	0%	0%	0%
23	Essex Co. RRF	Trf	2,793	430	(2,363)	0	0	0	32%	5%	(27%)	0%	0%	0%
24	Maywood	Trf	2,540	207	(2,333)	0	0	0	29%	2%	(27%)	0%	0%	0%
25	West Moulton - City Of St. Marys	Line	2,677	399	(2,278)	0	0	0	31%	5%	(26%)	0%	0%	0%

Constraint Costs

Table 11-28 and Table 11-29 show the top constraints affecting congestion costs by facility for 2018 and 2017. The AEP – DOM Interface was the largest contributor to congestion costs in 2018, with $121.0 million in total congestion costs and 9.2 percent of the total PJM congestion costs in 2018.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): 2018[22]

				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
1	AEP - DOM	Interface	500	$55.6	($66.9)	($5.3)	$117.2	$13.4	$18.7	$9.0	$3.8	$121.0	9.2%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	6.7%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($20.8)	($94.1)	($2.9)	$70.4	$0.0	$0.0	$0.0	$0.0	$70.4	5.4%
4	Graceton - Safe Harbor	Line	BGE	$95.3	$31.1	$2.4	$66.6	$0.6	$4.6	($1.6)	($5.6)	$61.0	4.7%
5	5004/5005 Interface	Interface	500	($15.4)	($54.4)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	2.7%
6	Batesville - Hubble	Flowgate	MISO	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$2.0	$34.5	2.6%
7	Conastone - Peach Bottom	Line	500	$29.8	$0.7	($0.2)	$28.9	$1.6	$0.8	($0.0)	$0.7	$29.6	2.3%
8	Pleasant View - Ashburn	Line	Dominion	$17.8	($8.4)	($0.9)	$25.4	$1.1	$1.1	$0.6	$0.6	$25.9	2.0%
9	Lakeview - Greenfield	Line	ATSI	($20.4)	($57.3)	($1.5)	$35.3	($1.4)	$8.9	$0.3	($10.0)	$25.3	1.9%
10	Bedington - Black Oak	Interface	500	$10.2	($14.0)	($1.4)	$22.7	$0.6	$0.7	$0.6	$0.5	$23.2	1.8%
11	Gardners - Texas East	Line	Met-Ed	($5.1)	($26.2)	($0.2)	$20.8	($0.3)	$0.1	$1.4	$1.0	$21.9	1.7%
12	Wescosville	Transformer	PPL	$3.2	($17.5)	($0.6)	$20.1	$0.4	$0.1	$0.9	$1.2	$21.3	1.6%
13	North Salisbury - Rockawalkin	Line	DPL	$26.4	$7.3	$1.7	$20.8	$0.0	$0.0	$0.0	$0.0	$20.8	1.6%
14	AP South	Interface	500	$14.1	($8.3)	($1.6)	$20.8	$0.1	$0.1	($0.0)	($0.0)	$20.8	1.6%
15	Capitol Hill - Chemical	Line	AEP	$12.3	($5.0)	$0.5	$17.9	$0.8	($0.8)	($0.1)	$1.5	$19.4	1.5%
16	Nottingham	Other	PECO	$20.5	$2.6	$0.7	$18.7	$0.0	$0.0	$0.0	$0.0	$18.7	1.4%
17	Maple - Jackson	Line	ATSI	($13.1)	($28.6)	$2.1	$17.7	$0.4	$0.8	($0.9)	($1.3)	$16.4	1.3%
18	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.2%
19	Cedar Creek - Red Lion	Line	DPL	$2.4	($12.1)	$0.8	$15.3	($0.8)	($1.8)	($0.6)	$0.4	$15.7	1.2%
20	Conastone - Northwest	Line	BGE	$14.6	($0.9)	($0.6)	$15.0	($1.1)	($0.4)	$0.8	$0.0	$15.0	1.1%
21	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.1%
22	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.0%
23	Krendale - Shanorma	Line	APS	($8.4)	($19.9)	$1.3	$12.8	$0.0	$0.0	$0.0	$0.0	$12.8	1.0%
24	Emilie - Falls	Line	PECO	$3.4	($7.6)	$0.4	$11.4	$0.2	$0.4	$0.4	$0.2	$11.6	0.9%
25	North Salisbury - Rockawalkin	Line	DPL	$0.0	$0.0	$0.0	$0.0	($4.6)	$4.2	($2.8)	($11.5)	($11.5)	(0.9%)
	Top 25 Total			$270.8	($504.7)	($27.3)	$748.1	$9.8	$34.5	$17.3	($7.4)	$740.7	56.5%
	All Other Constraints			$78.5	($543.9)	$8.4	$630.8	$1.7	$27.5	($35.9)	($61.6)	$569.2	43.5%
	Total			$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	100.0%

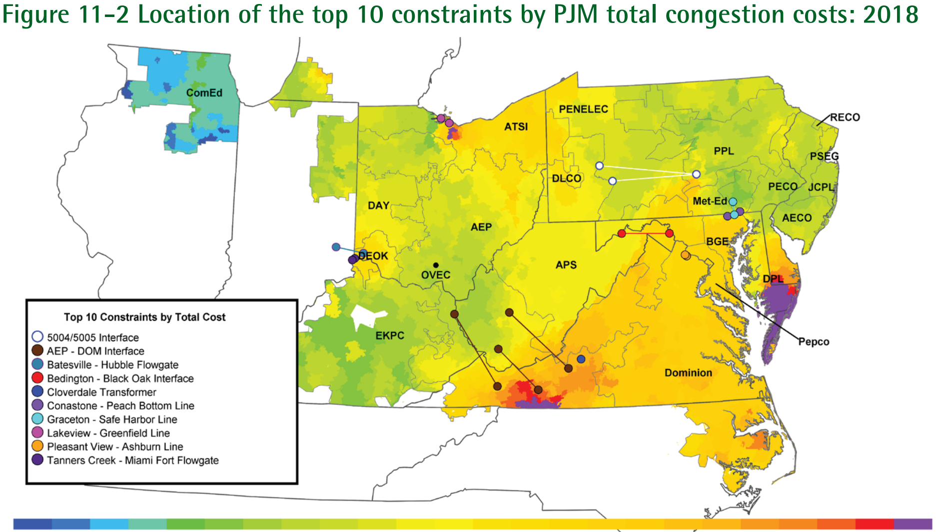
22 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-29 Top 25 constraints affecting PJM congestion costs (By facility): 2017[23]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
				Load	Generation	Explicit		Load	Generation	Explicit		Grand	
No.	Constraint	Type	Location	Payments	Credits	Costs	Total	Payments	Credits	Costs	Total	Total	2017
1	Braidwood - East Frankfort	Line	ComEd	($4.7)	($49.7)	$0.3	$45.3	$0.7	$1.9	($0.7)	($1.9)	$43.4	6.2%
2	Conastone - Peach Bottom	Line	500	$38.7	$1.6	$0.1	$37.2	$1.7	$1.2	$1.6	$2.0	$39.3	5.6%
3	Emilie - Falls	Line	PECO	$12.0	($13.6)	($0.1)	$25.6	$0.0	$1.2	$0.8	($0.4)	$25.2	3.6%
4	Graceton - Safe Harbor	Line	BGE	$30.2	$7.1	($0.0)	$23.1	$1.5	$2.2	$1.5	$0.7	$23.8	3.4%
5	5004/5005 Interface	Interface	500	($9.9)	($38.7)	($3.8)	$25.0	$4.5	$11.4	$4.6	($2.4)	$22.7	3.3%
6	AP South	Interface	500	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	3.1%
7	Westwood	Flowgate	MISO	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	2.8%
8	Cherry Valley	Transformer	ComEd	$8.9	($10.1)	$2.1	$21.0	($0.6)	$0.9	($0.9)	($2.3)	$18.7	2.7%
9	Carson - Rawlings	Line	Dominion	$14.5	($4.3)	$0.8	$19.6	$1.1	$1.8	($0.8)	($1.5)	$18.1	2.6%
10	Conastone - Otter Creek	Line	PPL	$23.0	$8.5	($0.6)	$13.9	$1.3	$1.6	$1.4	$1.2	$15.1	2.2%
11	Conastone - Northwest	Line	BGE	$12.7	($1.1)	($0.4)	$13.4	$0.3	$0.7	$1.0	$0.6	$14.0	2.0%
12	Three Mile Island	Transformer	500	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.5)	$0.9	$1.3	$13.3	1.9%
13	Butler - Shanor Manor	Line	APS	($10.5)	($20.9)	$1.0	$11.4	$1.7	$1.7	($0.4)	($0.3)	$11.1	1.6%
14	Lakeview - Greenfield	Line	ATSI	($3.5)	($14.5)	$0.2	$11.2	$0.1	$0.7	$0.3	($0.4)	$10.8	1.5%
15	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	1.5%
16	Bedington - Black Oak	Interface	500	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1.4%
17	Lake George - Aetna	Flowgate	MISO	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.9	$2.7	$9.1	1.3%
18	Person - Sedge Hill	Line	Dominion	$16.2	$3.5	$2.0	$14.7	$0.7	$3.0	($3.3)	($5.6)	$9.1	1.3%
19	Batesville - Hubble	Flowgate	MISO	($5.5)	($19.4)	($4.5)	$9.4	($0.1)	($1.3)	($1.7)	($0.5)	$8.9	1.3%
20	Byron - Cherry Valley	Flowgate	MISO	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	1.1%
21	AEP - DOM	Interface	500	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.4	$0.2	$0.3	$7.8	1.1%
22	Brunner Island - Yorkanna	Line	Met-Ed	$6.0	($1.6)	($0.3)	$7.3	($0.0)	($0.1)	$0.1	$0.2	$7.4	1.1%
23	Brokaw - Leroy	Flowgate	MISO	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1.0%
24	Loretto - Vienna	Line	DPL	$8.8	$2.3	$0.7	$7.2	($0.4)	$0.1	$0.2	($0.3)	$6.9	1.0%
25	Pleasant View - Ashburn	Line	Dominion	$5.8	($3.7)	($0.3)	$9.1	($1.2)	$1.0	($0.1)	($2.3)	$6.8	1.0%
	Top 25 Total			$148.5	($258.1)	($11.7)	$395.0	$11.0	$31.8	$14.0	($6.7)	$388.3	55.7%
	All Other Constraints			$39.0	($295.9)	$3.1	$338.1	$11.2	$15.4	($24.5)	($28.7)	$309.3	44.3%
	Total			$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	100.0%

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 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 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 2018.

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



23 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 11-3 Location of the top 10 constraints by PJM balancing congestion costs: 2018

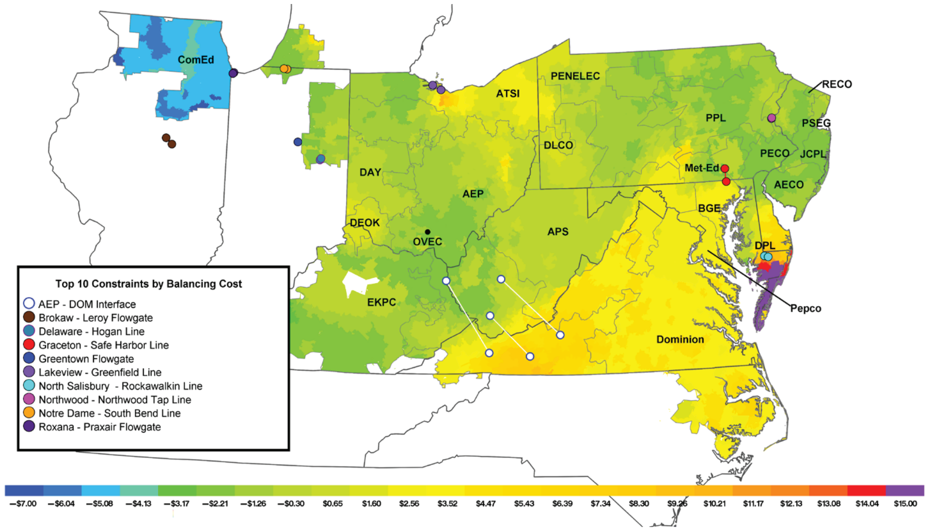
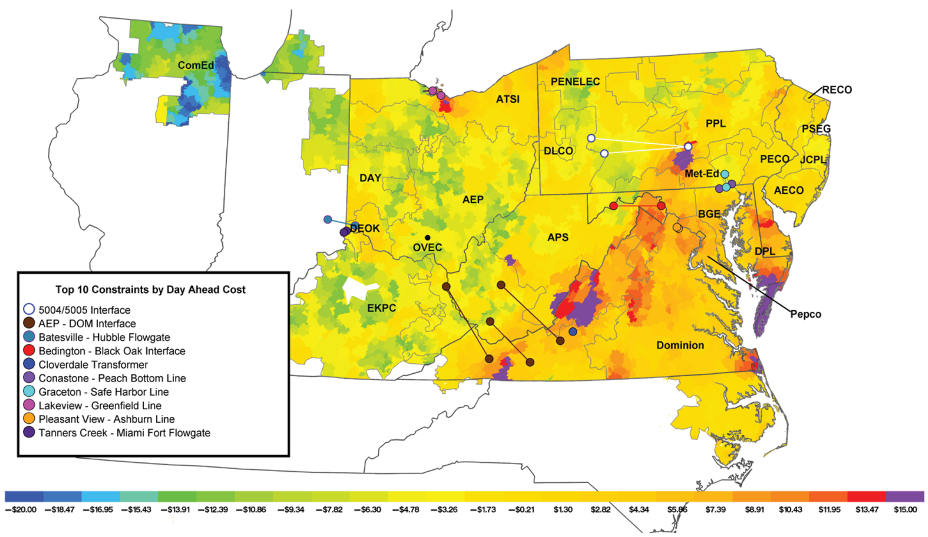


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: 2018



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 nine control zones (the AP, ATSI, ComEd, AEP, DLCO, DEOK, DAY, EKPC and OVEC control zones); and the PJM South Region with one control zone (the Dominion Control Zone).[24]

Table 11-30 through Table 11-50 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 2018. The tables present the top 20 constraints in descending order of the absolute value of congestion costs for each zone using constraint based

24 See PJM Operating Agreement § 1.

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 11-30 AECO Control Zone top congestion cost impacts (By facility): 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	$6.5	($2.2)	$4.2	$1.8	($0.1)	$1.7	2,858	500
2	AEP - DOM	Interface	500	$0.3	$0.0	$0.3	$1.3	$0.0	$1.4	720	150
3	Cloverdale	Transformer	AEP	$0.8	$0.2	$1.0	$1.0	$0.0	$1.1	615	99
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.9	$0.0	$0.9	1,511	0
5	5004/5005 Interface	Interface	500	$1.7	$0.2	$1.9	$0.7	$0.0	$0.7	175	47
6	Graceton - Safe Harbor	Line	BGE	($2.9)	($1.5)	($4.4)	$0.6	($0.1)	$0.6	3,361	2,046
7	Gardners - Texas East	Line	Met-Ed	($0.4)	($0.1)	($0.4)	$0.5	$0.0	$0.5	2,788	439
8	Emilie - Falls	Line	PECO	$0.1	$0.0	$0.1	$0.4	$0.0	$0.4	1,593	329
9	Batesville - Hubble	Flowgate	MISO	($0.1)	($0.0)	($0.1)	$0.4	$0.0	$0.4	254	134
10	Lakeview - Greenfield	Line	ATSI	$0.5	$0.1	$0.6	$0.5	($0.1)	$0.4	1,356	352
11	Wescosville	Transformer	PPL	$0.2	$0.0	$0.2	$0.3	$0.0	$0.4	553	172
12	Pleasant View - Ashburn	Line	Dominion	($0.3)	($0.1)	($0.5)	$0.3	$0.0	$0.3	303	33
13	Chambers	Transformer	AECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	381	0
14	Bedington - Black Oak	Interface	500	$0.2	$0.0	$0.2	$0.3	$0.0	$0.3	316	52
15	Cedar Creek - Red Lion	Line	DPL	($0.2)	($0.1)	($0.2)	$0.3	$0.0	$0.3	918	69
16	AP South	Interface	500	$0.1	($0.0)	$0.1	$0.3	($0.0)	$0.3	498	37
17	Maple - Jackson	Line	ATSI	($0.4)	($0.1)	($0.4)	$0.2	($0.0)	$0.2	1,000	155
18	Person - Sedge Hill	Line	Dominion	$0.1	$0.0	$0.1	$0.2	($0.0)	$0.2	814	136
19	East Towanda - North Meshoppen	Line	PENELEC	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	605	0
20	Riverside	Line	BGE	$0.1	$0.0	$0.1	$0.2	($0.0)	$0.2	266	69
	Top 20 Total			$6.7	($3.5)	$3.2	$10.8	($0.1)	$10.6	20,885	4,819
	All Other Constraints			($4.3)	($1.9)	($6.3)	$6.1	($0.7)	$5.3	77,972	18,466
	Total			$2.4	($5.4)	($3.0)	$16.9	($0.9)	$16.0	98,857	23,285

BGE Control Zone

Table 11-31 BGE Control Zone top congestion cost impacts (By facility): 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	$0.5	$0.6	$1.0	$5.6	$0.2	$5.8	720	150
2	Cloverdale	Transformer	AEP	$1.2	$0.5	$1.7	$4.1	$0.1	$4.2	615	99
3	Graceton - Safe Harbor	Line	BGE	$19.6	($1.4)	$18.2	$3.5	($0.3)	$3.2	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$2.8	$0.0	$2.8	1,511	0
5	5004/5005 Interface	Interface	500	$1.6	$0.3	$2.0	$1.8	$0.1	$1.9	175	47
6	Conastone - Peach Bottom	Line	500	$5.1	($0.7)	$4.4	$1.7	$0.0	$1.8	1,100	422
7	Batesville - Hubble	Flowgate	MISO	($0.1)	($0.0)	($0.1)	$1.3	$0.1	$1.4	254	134
8	Bedington - Black Oak	Interface	500	$0.9	$0.2	$1.0	$1.2	$0.0	$1.2	316	52
9	Conastone - Northwest	Line	BGE	$4.7	($0.8)	$3.9	$1.2	$0.0	$1.2	336	234
10	AP South	Interface	500	$0.7	($0.0)	$0.7	$1.1	($0.0)	$1.1	498	37
11	BCPEP	Interface	Pepco	$0.8	$0.0	$0.8	$1.0	$0.0	$1.0	126	0
12	Lakeview - Greenfield	Line	ATSI	$1.4	$0.3	$1.7	$1.4	($0.4)	$1.0	1,356	352
13	Pleasant View - Ashburn	Line	Dominion	($2.3)	($0.0)	($2.3)	$0.9	$0.0	$0.9	303	33
14	Gardners - Texas East	Line	Met-Ed	($0.7)	$0.2	($0.5)	$0.9	$0.0	$0.9	2,788	439
15	Nottingham	Other	PECO	$3.2	$0.0	$3.2	$0.9	$0.0	$0.9	1,157	390
16	Bagley - Graceton	Line	BGE	$3.5	$0.0	$3.6	$0.8	($0.0)	$0.7	595	214
17	Person - Sedge Hill	Line	Dominion	$0.7	$0.0	$0.7	$0.7	($0.0)	$0.7	814	136
18	Maple - Jackson	Line	ATSI	($1.3)	$0.1	($1.2)	$0.7	($0.0)	$0.7	1,000	155
19	Northport - Albion	Flowgate	MISO	$0.1	$0.0	$0.1	$0.5	$0.1	$0.6	132	28
20	Brokaw - Leroy	Flowgate	MISO	$0.4	$0.0	$0.5	$0.4	$0.2	$0.6	1,232	261
	Top 20 Total			$39.8	($0.7)	$39.1	$32.5	$0.1	$32.6	18,389	5,229
	All Other Constraints			$17.6	$0.1	$17.7	$15.6	($2.3)	$13.3	77,235	17,986
	Total			$57.5	($0.7)	$56.8	$48.1	($2.2)	$45.9	95,624	23,215

DPL Control Zone

Table 11-32 DPL Control Zone top congestion cost impacts (By facility): 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	North Salisbury - Rockawalkin	Line	DPL	$20.7	$0.0	$20.7	$19.8	$0.0	$19.8	1,610	0
2	Cedar Creek - Clayton	Line	DPL	$8.4	($0.2)	$8.2	$7.9	($0.0)	$7.9	876	39
3	Loretto - Vienna	Line	DPL	$6.2	$0.1	$6.3	$6.3	$0.0	$6.3	936	5
4	Cedar Creek - Red Lion	Line	DPL	$13.8	$0.6	$14.4	$4.5	$0.1	$4.6	918	69
5	Kent - Vaughn	Line	DPL	$3.7	($0.5)	$3.3	$3.8	($0.0)	$3.8	504	57
6	Preston - Tanyard	Line	DPL	$3.5	$0.0	$3.6	$3.6	$0.0	$3.6	918	11
7	AEP - DOM	Interface	500	$1.2	($0.5)	$0.7	$3.3	$0.1	$3.4	720	150
8	Cloverdale	Transformer	AEP	$3.6	($1.0)	$2.6	$2.5	$0.0	$2.5	615	99
9	Dupont Seaford - Laurel	Line	DPL	$2.9	$0.0	$2.9	$2.0	$0.0	$2.0	259	0
10	North Salisbury - Pemberton	Line	DPL	$2.2	($0.3)	$1.9	$2.2	($0.3)	$1.9	469	109
11	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$1.7	$0.0	$1.7	1,511	0
12	5004/5005 Interface	Interface	500	$5.9	($0.4)	$5.5	$1.6	$0.1	$1.7	175	47
13	Church - New Meredith	Line	DPL	$1.4	$0.0	$1.4	$1.4	$0.0	$1.4	301	0
14	Gardners - Texas East	Line	Met-Ed	($2.1)	$0.3	($1.8)	$1.1	$0.0	$1.1	2,788	439
15	Graceton - Safe Harbor	Line	BGE	($13.6)	$3.0	($10.7)	$1.2	($0.1)	$1.1	3,361	2,046
16	Easton - Emuni	Line	DPL	$0.9	($0.0)	$0.9	$0.9	($0.0)	$0.9	3,831	2
17	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.6	$1.2	($0.3)	$0.9	1,356	352
18	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.8	$0.1	$0.9	254	134
19	Easton	Transformer	DPL	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	101	14
20	Emilie - Falls	Line	PECO	($1.1)	$0.3	($0.8)	$0.9	$0.0	$0.9	1,593	329
	Top 20 Total			$60.3	$0.7	$61.0	$67.7	($0.3)	$67.4	23,096	3,902
	All Other Constraints			($6.1)	($10.2)	($16.3)	$20.2	($2.0)	$18.2	75,708	19,383
	Total			$54.2	($9.5)	$44.7	$87.8	($2.3)	$85.5	98,804	23,285

JCPL Control Zone

Table 11-33 JCPL Control Zone top congestion cost impacts (By facility): 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	$1.5	($0.2)	$1.3	$3.0	$0.1	$3.2	720	150
2	Cloverdale	Transformer	AEP	$3.9	($1.1)	$2.8	$2.4	$0.0	$2.5	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$2.0	$0.0	$2.0	1,511	0
4	5004/5005 Interface	Interface	500	$6.8	($1.3)	$5.4	$1.6	$0.1	$1.7	175	47
5	Emilie - Falls	Line	PECO	$1.3	$0.2	$1.5	$1.5	$0.0	$1.5	1,593	329
6	Northwood	Transformer	Met-Ed	$1.3	$0.1	$1.4	$1.4	($0.0)	$1.4	64	15
7	Monroe - Vineland	Line	AECO	$0.3	$0.1	$0.4	$1.5	($0.1)	$1.4	2,858	500
8	Graceton - Safe Harbor	Line	BGE	($1.9)	($3.4)	($5.3)	$1.4	($0.1)	$1.3	3,361	2,046
9	Gardners - Texas East	Line	Met-Ed	($0.7)	($0.3)	($1.0)	$1.2	$0.0	$1.3	2,788	439
10	Northwood - Northwood Tap	Line	Met-Ed	$1.0	($0.4)	$0.6	$1.2	($0.2)	$1.0	56	72
11	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.9	$0.0	$1.0	254	134
12	Wescosville	Transformer	PPL	$1.2	$0.3	$1.5	$0.9	$0.0	$1.0	553	172
13	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.5	$1.2	($0.3)	$0.9	1,356	352
14	North Meshoppen	Transformer	PENELEC	$1.2	($0.1)	$1.1	$0.9	$0.0	$0.9	378	71
15	Pleasant View - Ashburn	Line	Dominion	($0.5)	($0.2)	($0.7)	$0.7	$0.0	$0.7	303	33
16	Middletown Jct	Transformer	Met-Ed	($0.4)	$0.0	($0.4)	$0.6	$0.0	$0.6	720	0
17	Bedington - Black Oak	Interface	500	$0.6	($0.1)	$0.5	$0.6	$0.0	$0.6	316	52
18	Cedar Creek - Red Lion	Line	DPL	($0.2)	($0.0)	($0.2)	$0.6	$0.0	$0.6	918	69
19	AP South	Interface	500	$0.2	($0.0)	$0.2	$0.6	($0.0)	$0.6	498	37
20	Maple - Jackson	Line	ATSI	($0.3)	($0.3)	($0.6)	$0.5	($0.0)	$0.5	1,000	155
	Top 20 Total			$16.8	($7.4)	$9.4	$24.9	($0.3)	$24.6	20,037	4,772
	All Other Constraints			$2.6	($7.1)	($4.4)	$14.3	($1.4)	$12.9	78,851	18,513
	Total			$19.4	($14.4)	$5.0	$39.2	($1.7)	$37.5	98,888	23,285

Met-Ed Control Zone

Table 11-34 Met-Ed Control Zone top congestion cost impacts (By facility): 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	Middletown Jct	Transformer	Met-Ed	$7.3	$0.0	$7.3	$2.5	$0.0	$2.5	720	0
2	AEP - DOM	Interface	500	$0.2	($0.2)	($0.0)	$2.3	$0.1	$2.4	720	150
3	Gardners - Texas East	Line	Met-Ed	$10.7	($0.4)	$10.3	$2.1	($0.0)	$2.0	2,788	439
4	Hunterstown	Transformer	500	$1.9	$0.0	$1.9	$1.9	$0.0	$1.9	169	367
5	Cloverdale	Transformer	AEP	$0.2	($0.6)	($0.4)	$1.8	$0.0	$1.8	615	99
6	Tanners Creek - Miami Fort	Flowgate	MISO	$0.0	$0.0	$0.0	$1.3	$0.0	$1.3	1,511	0
7	5004/5005 Interface	Interface	500	($0.3)	($0.5)	($0.8)	$1.1	$0.0	$1.2	175	47
8	Ironwood - South Lebanon	Line	Met-Ed	$1.0	($0.2)	$0.9	$1.0	($0.1)	$1.0	238	212
9	Graceton - Safe Harbor	Line	BGE	$1.5	$0.6	$2.1	$0.8	($0.1)	$0.8	3,361	2,046
10	Lakeview - Greenfield	Line	ATSI	($0.2)	($0.5)	($0.6)	$0.9	($0.2)	$0.7	1,356	352
11	Batesville - Hubble	Flowgate	MISO	$0.0	$0.0	$0.0	$0.6	$0.0	$0.6	254	134
12	Northwood	Transformer	Met-Ed	$1.1	($0.1)	$1.0	$0.6	($0.0)	$0.6	64	15
13	Wescosville	Transformer	PPL	$0.6	($0.0)	$0.6	$0.6	$0.0	$0.6	553	172
14	Emilie - Falls	Line	PECO	$0.2	($0.0)	$0.2	$0.6	$0.0	$0.6	1,593	329
15	Bedington - Black Oak	Interface	500	$0.1	($0.0)	$0.1	$0.5	$0.0	$0.5	316	52
16	Pleasant View - Ashburn	Line	Dominion	$0.6	($0.1)	$0.6	$0.5	$0.0	$0.5	303	33
17	AP South	Interface	500	($0.0)	$0.0	($0.0)	$0.4	($0.0)	$0.4	498	37
18	Northwood - Northwood Tap	Line	Met-Ed	$0.8	($1.0)	($0.1)	$0.5	($0.1)	$0.4	56	72
19	Conastone - Peach Bottom	Line	500	$0.1	($0.1)	($0.1)	$0.4	$0.0	$0.4	1,100	422
20	Hunterstown	Transformer	Met-Ed	$0.2	($0.5)	($0.3)	$0.1	($0.5)	($0.4)	169	367
	Top 20 Total			$26.1	($3.6)	$22.5	$20.7	($0.7)	$19.9	16,559	5,345
	All Other Constraints			$11.5	($2.2)	$9.3	$10.9	($0.9)	$10.0	81,866	18,237
	Total			$37.6	($5.7)	$31.8	$31.6	($1.6)	$29.9	98,425	23,582

PECO Control Zone

Table 11-35 PECO Control Zone top congestion cost impacts (By facility): 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	($1.1)	$0.6	($0.4)	$5.9	$0.2	$6.1	720	150
2	Cloverdale	Transformer	AEP	($3.2)	$1.5	($1.8)	$4.6	$0.1	$4.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.3	$0.0	$0.3	$3.5	$0.0	$3.5	1,511	0
4	5004/5005 Interface	Interface	500	($3.5)	$0.1	($3.4)	$3.0	$0.1	$3.1	175	47
5	Gardners - Texas East	Line	Met-Ed	$4.0	($0.1)	$3.9	$2.5	$0.1	$2.5	2,788	439
6	Graceton - Safe Harbor	Line	BGE	$37.7	($0.4)	$37.3	$2.7	($0.2)	$2.5	3,361	2,046
7	Emilie - Falls	Line	PECO	$3.2	($0.5)	$2.6	$1.8	$0.0	$1.9	1,593	329
8	Lakeview - Greenfield	Line	ATSI	($2.6)	$0.5	($2.1)	$2.3	($0.5)	$1.8	1,356	352
9	Batesville - Hubble	Flowgate	MISO	$0.2	($0.0)	$0.2	$1.6	$0.1	$1.7	254	134
10	Wescosville	Transformer	PPL	($0.2)	$0.1	($0.0)	$1.5	$0.1	$1.6	553	172
11	Pleasant View - Ashburn	Line	Dominion	$2.3	($0.3)	$2.1	$1.2	$0.0	$1.2	303	33
12	Bedington - Black Oak	Interface	500	($1.2)	$0.1	($1.1)	$1.2	$0.0	$1.2	316	52
13	Monroe - Vineland	Line	AECO	$0.0	($0.2)	($0.1)	$1.3	($0.1)	$1.2	2,858	500
14	AP South	Interface	500	($0.8)	($0.0)	($0.8)	$1.1	($0.0)	$1.1	498	37
15	Person - Sedge Hill	Line	Dominion	($1.1)	$0.0	($1.0)	$0.9	($0.0)	$0.8	814	136
16	Maple - Jackson	Line	ATSI	$4.4	($0.1)	$4.4	$0.9	($0.1)	$0.8	1,000	155
17	East Townada - North Meshoppen	Line	PENELEC	($0.2)	$0.0	($0.2)	$0.8	$0.0	$0.8	605	0
18	Middletown Jct	Transformer	Met-Ed	$1.8	$0.0	$1.8	$0.7	$0.0	$0.7	720	0
19	Roxana - Praxair	Flowgate	MISO	($3.3)	$0.3	($3.0)	($0.4)	($0.3)	($0.7)	1,132	481
20	Northport - Albion	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.6	$0.1	$0.7	132	28
	Top 20 Total			$36.7	$1.8	$38.5	$37.6	($0.5)	$37.1	21,304	5,190
	All Other Constraints			$66.5	($3.1)	$63.4	$24.8	($2.3)	$22.5	76,740	18,095
	Total			$103.3	($1.3)	$101.9	$62.4	($2.8)	$59.6	98,044	23,285

PENELEC Control Zone

Table 11-36 PENELEC Control Zone top congestion cost impacts (By facility): 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	$1.3	($0.2)	$1.0	$2.3	$0.1	$2.3	720	150
2	Cloverdale	Transformer	AEP	($3.0)	($0.1)	($3.0)	$1.6	$0.0	$1.6	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.5	$0.0	$0.5	$1.4	$0.0	$1.4	1,511	0
4	Titusville - Union City	Line	PENELEC	$2.2	$0.1	$2.3	$1.3	($0.0)	$1.3	302	76
5	Graceton - Safe Harbor	Line	BGE	$9.4	($0.2)	$9.2	$1.4	($0.1)	$1.3	3,361	2,046
6	Gardners - Texas East	Line	Met-Ed	$4.7	$0.5	$5.2	$1.2	$0.0	$1.2	2,788	439
7	Niles Valley - Sabinsville	Line	PENELEC	$0.0	($1.1)	($1.1)	$0.0	($1.1)	($1.1)	0	112
8	Lakeview - Greenfield	Line	ATSI	($5.4)	($0.3)	($5.7)	$1.1	($0.2)	$0.8	1,356	352
9	Middletown Jct	Transformer	Met-Ed	$0.4	$0.0	$0.4	$0.8	$0.0	$0.8	720	0
10	Asylum	Transformer	PENELEC	$0.7	$0.0	$0.7	$0.7	$0.0	$0.7	381	0
11	Batesville - Hubble	Flowgate	MISO	$0.4	$0.0	$0.4	$0.7	$0.0	$0.7	254	134
12	Wescosville	Transformer	PPL	$1.3	($0.2)	$1.1	$0.7	$0.0	$0.7	553	172
13	North Meshoppen	Transformer	PENELEC	$1.3	$0.9	$2.3	$0.6	$0.0	$0.6	378	71
14	5004/5005 Interface	Interface	500	$10.8	$0.5	$11.3	$0.6	$0.0	$0.6	175	47
15	Emilie - Falls	Line	PECO	($0.1)	$0.0	($0.1)	$0.6	$0.0	$0.6	1,593	329
16	Pleasant View - Ashburn	Line	Dominion	$1.4	($0.1)	$1.3	$0.5	$0.0	$0.5	303	33
17	Conastone - Peach Bottom	Line	500	$1.8	$0.2	$2.0	$0.5	$0.0	$0.5	1,100	422
18	Bedington - Black Oak	Interface	500	$2.7	$0.0	$2.7	$0.4	$0.0	$0.4	316	52
19	Roxana - Praxair	Flowgate	MISO	($2.3)	$0.3	($2.0)	($0.3)	($0.1)	($0.4)	1,132	481
20	Nottingham	Other	PECO	$0.6	$0.0	$0.6	$0.4	$0.0	$0.4	1,157	390
	Top 20 Total			$28.7	$0.1	$28.9	$16.4	($1.3)	$15.1	18,715	5,405
	All Other Constraints			$46.7	($2.7)	$44.0	$15.6	($0.9)	$14.8	81,979	17,810
	Total			$75.4	($2.6)	$72.8	$32.1	($2.2)	$29.9	100,694	23,215

Pepco Control Zone

Table 11-37 Pepco Control Zone top congestion cost impacts (By facility): 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	$5.0	($0.6)	$4.4	$5.5	$0.2	$5.7	720	150
2	Cloverdale	Transformer	AEP	$5.9	$0.6	$6.5	$4.0	$0.1	$4.0	615	99
3	Graceton - Safe Harbor	Line	BGE	$14.8	$1.4	$16.3	$3.3	($0.3)	$3.0	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$2.7	$0.0	$2.7	1,511	0
5	Conastone - Peach Bottom	Line	500	$5.2	$0.3	$5.5	$1.7	$0.0	$1.7	1,100	422
6	5004/5005 Interface	Interface	500	$0.9	$0.1	$1.0	$1.5	$0.1	$1.6	175	47
7	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$1.3	$0.1	$1.4	254	134
8	Bedington - Black Oak	Interface	500	$2.9	$0.1	$3.0	$1.2	$0.0	$1.2	316	52
9	AP South	Interface	500	$2.1	$0.0	$2.2	$1.1	($0.0)	$1.1	498	37
10	Conastone - Northwest	Line	BGE	$2.2	$0.4	$2.7	$1.0	$0.0	$1.0	336	234
11	BCPEP	Interface	Pepco	$1.0	$0.0	$1.0	$1.0	$0.0	$1.0	126	0
12	Pleasant View - Ashburn	Line	Dominion	($2.7)	($0.2)	($2.9)	$0.9	$0.0	$0.9	303	33
13	Nottingham	Other	PECO	$3.1	$0.0	$3.1	$0.8	$0.0	$0.8	1,157	390
14	Person - Sedge Hill	Line	Dominion	$1.4	($0.0)	$1.3	$0.7	($0.0)	$0.7	814	136
15	Maple - Jackson	Line	ATSI	($0.9)	($0.1)	($1.0)	$0.7	($0.0)	$0.7	1,000	155
16	Bagley - Graceton	Line	BGE	$1.7	$0.1	$1.8	$0.6	($0.0)	$0.6	595	214
17	Gardners - Texas East	Line	Met-Ed	$0.2	$0.0	$0.2	$0.6	$0.0	$0.6	2,788	439
18	Northport - Albion	Flowgate	MISO	$0.3	($0.0)	$0.3	$0.5	$0.1	$0.6	132	28
19	Brokaw - Leroy	Flowgate	MISO	$0.8	($0.0)	$0.7	$0.3	$0.2	$0.5	1,232	261
20	Cedar Grove Sub - Roseland	Line	PSEG	($0.4)	($0.1)	($0.4)	$0.5	($0.0)	$0.5	1,368	64
	Top 20 Total			$43.0	$2.0	$45.0	$30.0	$0.4	$30.4	18,401	4,941
	All Other Constraints			$4.8	$1.8	$6.5	$14.6	($2.4)	$12.2	76,732	18,274
	Total			$47.8	$3.8	$51.5	$44.6	($1.9)	$42.6	95,133	23,215

PPL Control Zone

Table 11-38 PPL Control Zone top congestion cost impacts (By facility): 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	($1.4)	$0.7	($0.7)	$6.5	$0.2	$6.7	720	150
2	Cloverdale	Transformer	AEP	($3.4)	$2.5	($0.8)	$5.1	$0.1	$5.2	615	99
3	5004/5005 Interface	Interface	500	($8.9)	$3.7	($5.1)	$3.4	$0.1	$3.5	175	47
4	Tanners Creek - Miami Fort	Flowgate	MISO	$0.3	$0.0	$0.3	$3.5	$0.0	$3.5	1,511	0
5	Gardners - Texas East	Line	Met-Ed	$1.1	($0.4)	$0.8	$2.8	$0.1	$2.8	2,788	439
6	Wescosville	Transformer	PPL	$15.8	$1.2	$17.0	$2.1	$0.1	$2.2	553	172
7	Graceton - Safe Harbor	Line	BGE	$4.6	($3.2)	$1.3	$2.3	($0.2)	$2.2	3,361	2,046
8	Lakeview - Greenfield	Line	ATSI	($2.6)	$2.5	($0.0)	$2.6	($0.5)	$2.1	1,356	352
9	Batesville - Hubble	Flowgate	MISO	$0.3	($0.0)	$0.2	$1.7	$0.1	$1.8	254	134
10	Emilie - Falls	Line	PECO	($0.8)	$0.1	($0.7)	$1.7	$0.0	$1.8	1,593	329
11	North Meshoppen	Transformer	PENELEC	($2.6)	$0.4	($2.2)	($1.7)	$0.1	($1.7)	378	71
12	Middletown Jct	Transformer	Met-Ed	$0.4	$0.0	$0.4	$1.5	$0.0	$1.5	720	0
13	Northwood	Transformer	Met-Ed	$2.4	($0.1)	$2.3	$1.4	($0.0)	$1.4	64	15
14	Bedington - Black Oak	Interface	500	($0.1)	$0.1	$0.1	$1.3	$0.0	$1.3	316	52
15	Pleasant View - Ashburn	Line	Dominion	$1.4	$0.2	$1.6	$1.2	$0.0	$1.2	303	33
16	AP South	Interface	500	$0.0	$0.0	$0.0	$1.0	($0.0)	$1.0	498	37
17	Northwood - Northwood Tap	Line	Met-Ed	$2.1	($2.8)	($0.8)	$1.2	($0.3)	$0.9	56	72
18	Quarry - Steel City	Line	PPL	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	126	84
19	Person - Sedge Hill	Line	Dominion	($0.5)	$0.2	($0.3)	$0.9	($0.0)	$0.9	814	136
20	Nottingham	Other	PECO	$3.1	$0.0	$3.1	$0.8	$0.0	$0.8	1,157	390
	Top 20 Total			$12.3	$5.0	$17.4	$40.1	($0.2)	$39.9	17,358	4,658
	All Other Constraints			$32.8	$6.1	$38.9	$29.8	($2.4)	$27.4	83,079	18,711
	Total			$45.1	$11.2	$56.3	$69.9	($2.6)	$67.3	100,437	23,369

PSEG Control Zone

Table 11-39 PSEG Control Zone top congestion cost impacts (By facility): 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	$0.4	($0.5)	($0.1)	$5.7	$0.2	$5.9	720	150
2	Cloverdale	Transformer	AEP	$1.6	($1.3)	$0.3	$4.6	$0.1	$4.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.2)	$0.0	($0.2)	$3.7	$0.0	$3.7	1,511	0
4	5004/5005 Interface	Interface	500	$5.3	($1.1)	$4.2	$2.9	$0.1	$3.0	175	47
5	Emilie - Falls	Line	PECO	$7.7	($0.0)	$7.6	$2.8	$0.0	$2.8	1,593	329
6	Graceton - Safe Harbor	Line	BGE	$0.8	$0.2	$1.0	$2.8	($0.2)	$2.5	3,361	2,046
7	Gardners - Texas East	Line	Met-Ed	$0.1	$0.6	$0.7	$2.4	$0.1	$2.4	2,788	439
8	Monroe - Vineland	Line	AECO	($0.1)	($0.1)	($0.1)	$2.2	($0.1)	$2.1	2,858	500
9	Northwood	Transformer	Met-Ed	$1.1	($0.0)	$1.1	$2.0	($0.0)	$2.0	64	15
10	Wescosville	Transformer	PPL	$0.4	($0.4)	$0.0	$1.7	$0.1	$1.8	553	172
11	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.0	($0.1)	$1.7	$0.1	$1.8	254	134
12	Cedar Grove Sub - Roseland	Line	PSEG	$9.1	($0.2)	$8.9	$1.7	($0.1)	$1.7	1,368	64
13	Pleasant View - Ashburn	Line	Dominion	$0.5	$0.1	$0.5	$1.4	$0.0	$1.4	303	33
14	Northwood - Northwood Tap	Line	Met-Ed	$0.9	($0.9)	($0.1)	$1.7	($0.3)	$1.4	56	72
15	Lakeview - Greenfield	Line	ATSI	$0.2	($1.2)	($1.0)	$1.9	($0.5)	$1.4	1,356	352
16	Bedington - Black Oak	Interface	500	($0.0)	($0.1)	($0.1)	$1.2	$0.0	$1.2	316	52
17	Cedar Creek - Red Lion	Line	DPL	$0.2	$0.2	$0.4	$1.1	$0.0	$1.2	918	69
18	AP South	Interface	500	($0.2)	$0.0	($0.2)	$1.0	($0.0)	$1.0	498	37
19	Maple - Jackson	Line	ATSI	($0.0)	$0.3	$0.2	$1.0	($0.1)	$0.9	1,000	155
20	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.9	($0.0)	$0.9	814	136
	Top 20 Total			$27.8	($4.6)	$23.3	$44.4	($0.7)	$43.8	21,121	4,901
	All Other Constraints			$24.8	($1.9)	$22.9	$29.0	($3.3)	$25.6	79,821	18,384
	Total			$52.7	($6.5)	$46.2	$73.4	($4.0)	$69.4	100,942	23,285

RECO Control Zone

Table 11-40 RECO Control Zone top congestion cost impacts (By facility): 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	Burns - Corporate Road	Line	RECO	$0.4	$0.0	$0.4	$0.4	$0.0	$0.4	511	0
2	Maywood - Saddlebrook	Line	PSEG	$0.3	($0.7)	($0.3)	($0.0)	($0.2)	($0.2)	417	98
3	Cedar Grove - Jackson Rd	Line	PSEG	$0.1	($0.4)	($0.3)	($0.0)	($0.2)	($0.2)	213	56
4	AEP - DOM	Interface	500	$0.0	($0.0)	$0.0	$0.2	$0.0	$0.2	720	150
5	Cloverdale	Transformer	AEP	$0.2	$0.0	$0.2	$0.1	$0.0	$0.1	615	99
6	Tanners Creek - Miami Fort	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.1	$0.0	$0.1	1,511	0
7	Emilie - Falls	Line	PECO	$0.3	($0.1)	$0.3	$0.1	$0.0	$0.1	1,593	329
8	5004/5005 Interface	Interface	500	$0.4	$0.0	$0.5	$0.1	$0.0	$0.1	175	47
9	Graceton - Safe Harbor	Line	BGE	($1.0)	($0.4)	($1.4)	$0.1	($0.0)	$0.1	3,361	2,046
10	Northwood	Transformer	Met-Ed	$0.1	$0.0	$0.1	$0.1	($0.0)	$0.1	64	15
11	Gardners - Texas East	Line	Met-Ed	($0.2)	$0.1	($0.1)	$0.1	$0.0	$0.1	2,788	439
12	Cedar Grove Sub - Roseland	Line	PSEG	$0.6	$0.0	$0.7	$0.1	($0.0)	$0.1	1,368	64
13	Northwood - Northwood Tap	Line	Met-Ed	$0.1	$0.0	$0.1	$0.1	($0.0)	$0.1	56	72
14	Batesville - Hubble	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.1	$0.0	$0.1	254	134
15	Wescosville	Transformer	PPL	$0.2	($0.2)	$0.1	$0.1	$0.0	$0.1	553	172
16	Pleasant View - Ashburn	Line	Dominion	($0.2)	$0.1	($0.1)	$0.1	$0.0	$0.1	303	33
17	Ramapo (ConEd) - S Mahwah (RECO)	Line	RECO	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	73	0
18	Cedar Creek - Red Lion	Line	DPL	($0.1)	$0.1	$0.0	$0.0	$0.0	$0.0	918	69
19	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	316	52
20	Maple - Jackson	Line	ATSI	($0.3)	$0.0	($0.3)	$0.0	($0.0)	$0.0	1,000	155
	Top 20 Total			$1.1	($1.3)	($0.2)	$1.7	($0.4)	$1.3	16,809	4,030
	All Other Constraints			($2.3)	$0.3	($2.0)	$0.9	($0.2)	$0.8	77,931	18,818
	Total			($1.2)	($1.0)	($2.2)	$2.6	($0.5)	$2.0	94,740	22,848

West Region Congestion-Event Summaries

AEP Control Zone

Table 11-41 AEP Control Zone top congestion cost impacts (By facility): 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	$94.8	($11.1)	$83.7	$18.9	$0.6	$19.4	720	150
2	Capitol Hill - Chemical	Line	AEP	$17.4	$0.9	$18.2	$15.6	$0.3	$15.9	510	98
3	Cloverdale	Transformer	AEP	$51.7	($4.1)	$47.6	$13.3	$0.2	$13.6	615	99
4	Tanners Creek - Miami Fort	Flowgate	MISO	$27.2	$0.0	$27.2	$11.5	$0.0	$11.5	1,511	0
5	Graceton - Safe Harbor	Line	BGE	($4.3)	$0.5	($3.8)	$12.1	($1.0)	$11.1	3,361	2,046
6	Batesville - Hubble	Flowgate	MISO	$9.9	($0.2)	$9.7	$5.3	$0.3	$5.7	254	134
7	Conastone - Peach Bottom	Line	500	($2.9)	($0.2)	($3.1)	$5.3	$0.1	$5.4	1,100	422
8	Lakeview - Greenfield	Line	ATSI	($0.5)	($2.4)	($2.9)	$6.0	($1.6)	$4.4	1,356	352
9	Pleasant View - Ashburn	Line	Dominion	$0.7	($0.0)	$0.6	$4.0	$0.1	$4.1	303	33
10	5004/5005 Interface	Interface	500	$11.6	($1.1)	$10.5	$3.9	$0.1	$4.0	175	47
11	Delaware - Hogan	Line	AEP	$8.0	($2.6)	$5.4	$4.5	($0.6)	$3.9	1,227	235
12	Bedington - Black Oak	Interface	500	$5.9	($0.5)	$5.4	$3.4	$0.1	$3.5	316	52
13	Nottingham	Other	PECO	($0.7)	$0.0	($0.7)	$3.3	$0.0	$3.3	1,157	390
14	Conastone - Northwest	Line	BGE	($1.0)	($0.0)	($1.0)	$3.0	$0.0	$3.0	336	234
15	AP South	Interface	500	$5.9	($0.1)	$5.9	$3.0	($0.0)	$3.0	498	37
16	Wescosville	Transformer	PPL	$0.4	$0.3	$0.7	$2.7	$0.2	$2.9	553	172
17	Delco Remy - Fall Creek	Line	AEP	$4.7	($1.1)	$3.6	$3.0	($0.2)	$2.7	247	18
18	Maple - Jackson	Line	ATSI	($0.4)	($0.2)	($0.6)	$3.0	($0.2)	$2.7	1,000	155
19	Gable Switch Station - South Cadiz	Line	AEP	$4.1	($0.8)	$3.3	$3.0	($0.2)	$2.7	284	106
20	Tanners Creek - Miami Fort	Line	AEP	$4.1	($1.8)	$2.2	$2.6	$0.1	$2.7	673	489
	Top 20 Total			$236.6	($24.6)	$212.0	$127.4	($1.9)	$125.6	16,196	5,269
	All Other Constraints			$121.7	($12.3)	$109.4	$107.5	($9.3)	$98.2	87,131	17,743
	Total			$358.2	($36.9)	$321.4	$234.9	($11.1)	$223.8	103,327	23,012

APS Control Zone

Table 11-42 APS Control Zone top congestion cost impacts (By facility): 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	$8.8	$0.5	$9.3	$7.5	$0.3	$7.8	720	150
2	Cloverdale	Transformer	AEP	$7.7	($0.3)	$7.4	$5.1	$0.1	$5.2	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$4.4	$0.0	$4.4	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$1.9	($0.9)	$1.0	$4.3	($0.4)	$4.0	3,361	2,046
5	Gardners - Texas East	Line	Met-Ed	$4.8	$0.4	$5.1	$2.1	$0.1	$2.2	2,788	439
6	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.0	($0.1)	$2.0	$0.1	$2.1	254	134
7	Conastone - Peach Bottom	Line	500	$0.9	($0.2)	$0.6	$2.0	$0.1	$2.0	1,100	422
8	Wescosville	Transformer	PPL	($0.2)	($0.1)	($0.3)	$1.8	$0.1	$1.9	553	172
9	5004/5005 Interface	Interface	500	$1.2	($0.2)	$1.0	$1.6	$0.1	$1.7	175	47
10	Pleasant View - Ashburn	Line	Dominion	($1.9)	($0.0)	($1.9)	$1.5	$0.0	$1.5	303	33
11	Bedington - Black Oak	Interface	500	$5.9	$0.5	$6.4	$1.4	$0.0	$1.5	316	52
12	Lakeview - Greenfield	Line	ATSI	$2.0	$0.0	$2.0	$2.1	($0.7)	$1.4	1,356	352
13	Gable Switch Station - South Cadiz	Line	AEP	($0.8)	$0.1	($0.7)	$1.4	($0.1)	$1.3	284	106
14	AP South	Interface	500	$6.2	($0.0)	$6.1	$1.2	($0.0)	$1.2	498	37
15	Nottingham	Other	PECO	$0.4	$0.0	$0.4	$1.2	$0.0	$1.2	1,157	390
16	Capitol Hill - Chemical	Line	AEP	$0.5	$0.1	$0.5	$1.0	$0.1	$1.1	510	98
17	Conastone - Northwest	Line	BGE	$0.4	$0.1	$0.5	$1.1	$0.0	$1.1	336	234
18	Maple - Jackson	Line	ATSI	($0.4)	$0.0	($0.4)	$1.1	($0.1)	$1.1	1,000	155
19	Person - Sedge Hill	Line	Dominion	$1.4	($0.0)	$1.4	$1.0	($0.0)	$1.0	814	136
20	Northport - Albion	Flowgate	MISO	$0.1	($0.0)	$0.1	$0.8	$0.1	$0.9	132	28
	Top 20 Total			$38.5	($0.1)	$38.4	$44.7	($0.1)	$44.5	17,783	5,130
	All Other Constraints			$16.4	($1.0)	$15.4	$35.3	($3.3)	$32.0	80,959	18,087
	Total			$54.9	($1.1)	$53.8	$79.9	($3.4)	$76.5	98,742	23,217

ATSI Control Zone

Table 11-43 ATSI Control Zone top congestion cost impacts (By facility): 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	($7.3)	($1.2)	($8.5)	$7.2	$0.2	$7.5	720	150
2	Cloverdale	Transformer	AEP	($3.7)	$0.2	($3.5)	$6.3	$0.1	$6.4	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.5	$0.0	$0.5	$5.9	$0.0	$5.9	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$3.4	($1.0)	$2.4	$5.3	($0.5)	$4.8	3,361	2,046
5	Lakeview - Greenfield	Line	ATSI	$35.3	($12.2)	$23.0	$4.0	($0.8)	$3.2	1,356	352
6	Batesville - Hubble	Flowgate	MISO	$0.1	($0.1)	$0.0	$2.6	$0.1	$2.7	254	134
7	Conastone - Peach Bottom	Line	500	$2.1	($0.4)	$1.7	$2.6	$0.1	$2.7	1,100	422
8	Wescosville	Transformer	PPL	($1.0)	$0.7	($0.3)	$2.3	$0.1	$2.4	553	172
9	Pleasant View - Ashburn	Line	Dominion	($1.1)	$0.5	($0.6)	$2.3	$0.0	$2.3	303	33
10	Gable Switch Station - South Cadiz	Line	AEP	$4.6	($0.9)	$3.7	$2.4	($0.2)	$2.2	284	106
11	Maple - Jackson	Line	ATSI	$11.2	($0.3)	$10.9	$1.9	($0.1)	$1.8	1,000	155
12	Nottingham	Other	PECO	$1.5	$0.0	$1.5	$1.7	$0.0	$1.7	1,157	390
13	5004/5005 Interface	Interface	500	($3.3)	$0.1	($3.2)	$1.6	$0.1	$1.6	175	47
14	Bedington - Black Oak	Interface	500	($1.9)	($0.0)	($1.9)	$1.5	$0.0	$1.5	316	52
15	Krendale - Shanorma	Line	APS	$8.6	$0.0	$8.6	$1.3	$0.0	$1.3	976	0
16	AP South	Interface	500	($3.1)	$0.1	($3.0)	$1.3	($0.0)	$1.3	498	37
17	Person - Sedge Hill	Line	Dominion	($1.4)	$0.1	($1.3)	$1.3	($0.0)	$1.2	814	136
18	Northport - Albion	Flowgate	MISO	$0.3	$0.1	$0.4	$0.9	$0.2	$1.1	132	28
19	Brokaw - Leroy	Flowgate	MISO	$1.3	($0.1)	$1.2	$0.7	$0.4	$1.1	1,232	261
20	North Salisbury - Rockawalkin	Line	DPL	$0.0	$0.5	$0.5	$0.0	($1.0)	($1.0)	0	784
	Top 20 Total			$46.2	($14.1)	$32.1	$53.1	($1.3)	$51.8	16,357	5,404
	All Other Constraints			$49.9	($6.5)	$43.4	$49.8	($4.2)	$45.6	80,406	17,597
	Total			$96.0	($20.6)	$75.5	$102.9	($5.5)	$97.4	96,763	23,001

ComEd Control Zone

Table 11-44 ComEd Control Zone top congestion cost impacts (By facility): 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	$8.7	$8.8	$17.5	$9.6	$0.3	$10.0	720	150
2	Cloverdale	Transformer	AEP	$14.5	$1.8	$16.3	$7.9	$0.1	$8.1	615	99
3	Graceton - Safe Harbor	Line	BGE	($5.3)	($2.1)	($7.4)	$8.7	($0.7)	$7.9	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	$8.9	$0.0	$8.9	$7.3	$0.0	$7.3	1,511	0
5	Davis	Transformer	ComEd	$6.4	$0.0	$6.4	$6.4	$0.0	$6.4	443	10
6	Quad Cities - Cordova	Flowgate	MISO	$8.4	$0.0	$8.4	$5.6	$0.0	$5.6	1,522	0
7	Quad Cities	Transformer	ComEd	$5.4	$0.0	$5.4	$5.4	$0.0	$5.4	2,614	0
8	Conastone - Peach Bottom	Line	500	($2.1)	$0.0	($2.1)	$4.2	$0.1	$4.3	1,100	422
9	Lakeview - Greenfield	Line	ATSI	$8.9	$3.6	$12.6	$5.2	($1.0)	$4.1	1,356	352
10	Delaware - Hogan	Line	AEP	$1.3	($0.0)	$1.3	$4.4	($0.4)	$3.9	1,227	235
11	Silver lake	Transformer	ComEd	$3.7	$0.0	$3.7	$3.6	$0.0	$3.6	104	0
12	Batesville - Hubble	Flowgate	MISO	$8.5	$0.8	$9.4	$3.2	$0.1	$3.3	254	134
13	Braidwood - East Frankfort	Line	ComEd	$4.9	($0.2)	$4.8	$3.2	($0.1)	$3.2	203	144
14	Cherry Valley	Transformer	ComEd	$3.1	$0.0	$3.1	$3.1	$0.0	$3.1	403	3
15	5004/5005 Interface	Interface	500	$3.9	$0.4	$4.3	$2.5	$0.1	$2.6	175	47
16	Belvidere - Chrysler Corp.	Line	ComEd	$2.5	$0.0	$2.5	$2.6	$0.0	$2.6	211	0
17	Nottingham	Other	PECO	($1.6)	$0.0	($1.6)	$2.4	$0.0	$2.4	1,157	390
18	Tollway	Transformer	ComEd	$2.3	$0.0	$2.3	$2.4	$0.0	$2.4	208	4
19	Bedington - Black Oak	Interface	500	$2.0	$0.4	$2.4	$2.1	$0.0	$2.2	316	52
20	Tanners Creek - Miami Fort	Line	AEP	$1.6	$3.1	$4.7	$2.2	($0.1)	$2.1	673	489
	Top 20 Total			$86.0	$16.8	$102.8	$92.1	($1.6)	$90.5	18,173	4,577
	All Other Constraints			$102.9	$28.4	$131.3	$80.1	($7.4)	$72.7	85,621	18,434
	Total			$188.9	$45.2	$234.1	$172.3	($9.0)	$163.2	103,794	23,011

DAY Control Zone

Table 11-45 DAY Control Zone top congestion cost impacts (By facility): 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	$5.2	$0.0	$5.2	$1.9	$0.0	$1.9	1,511	0
2	AEP - DOM	Interface	500	($1.0)	($1.4)	($2.3)	$1.8	$0.1	$1.8	720	150
3	Cloverdale	Transformer	AEP	($1.2)	($0.4)	($1.6)	$1.6	$0.0	$1.6	615	99
4	Graceton - Safe Harbor	Line	BGE	$1.9	$0.2	$2.1	$1.6	($0.1)	$1.5	3,361	2,046
5	Batesville - Hubble	Flowgate	MISO	$1.9	$0.6	$2.4	$0.9	$0.0	$0.9	254	134
6	Lakeview - Greenfield	Line	ATSI	($2.4)	($0.6)	($3.0)	$1.0	($0.2)	$0.8	1,356	352
7	Conastone - Peach Bottom	Line	500	$1.4	($0.1)	$1.3	$0.7	$0.0	$0.7	1,100	422
8	Tanners Creek - Miami Fort	Line	AEP	$0.6	$1.4	$2.0	$0.6	($0.0)	$0.5	673	489
9	5004/5005 Interface	Interface	500	($0.8)	$0.0	($0.8)	$0.5	$0.0	$0.5	175	47
10	Nottingham	Other	PECO	$0.8	$0.0	$0.8	$0.5	$0.0	$0.5	1,157	390
11	Terminal	Transformer	DEOK	($0.0)	$0.0	$0.0	$0.4	$0.0	$0.5	322	17
12	Bedington - Black Oak	Interface	500	($0.2)	($0.0)	($0.2)	$0.4	$0.0	$0.4	316	52
13	Conastone - Northwest	Line	BGE	$0.4	$0.1	$0.5	$0.4	($0.0)	$0.4	336	234
14	Pierce	Transformer	DEOK	$0.7	$0.0	$0.7	$0.4	$0.0	$0.4	305	0
15	Maple - Jackson	Line	ATSI	$0.6	($0.1)	$0.5	$0.4	($0.0)	$0.4	1,000	155
16	Delco Remy - Fall Creek	Line	AEP	$0.1	$0.0	$0.1	$0.4	($0.0)	$0.4	247	18
17	AP South	Interface	500	($0.6)	$0.0	($0.6)	$0.4	($0.0)	$0.4	498	37
18	Pleasant View - Ashburn	Line	Dominion	($0.4)	($0.0)	($0.4)	$0.3	$0.0	$0.3	303	33
19	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$0.6	($0.0)	$0.6	$0.3	($0.0)	$0.3	285	3
20	Krendale - Shanorma	Line	APS	$1.3	$0.0	$1.3	$0.3	$0.0	$0.3	976	0
	Top 20 Total			$9.0	($0.3)	$8.7	$14.9	($0.3)	$14.7	15,510	4,678
	All Other Constraints			$7.9	($1.5)	$6.3	$13.0	($1.1)	$11.9	85,682	18,334
	Total			$16.8	($1.8)	$15.0	$27.9	($1.4)	$26.5	101,192	23,012

DEOK Control Zone

Table 11-46 DEOK Control Zone top congestion cost impacts (By facility): 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	$29.5	$0.0	$29.5	$3.8	$0.0	$3.8	1,511	0
2	AEP - DOM	Interface	500	($4.8)	($4.4)	($9.2)	$2.8	$0.1	$2.9	720	150
3	Cloverdale	Transformer	AEP	($5.0)	($0.4)	($5.4)	$2.4	$0.0	$2.5	615	99
4	Graceton - Safe Harbor	Line	BGE	$3.6	($0.8)	$2.8	$2.6	($0.2)	$2.3	3,361	2,046
5	Batesville - Hubble	Flowgate	MISO	$21.2	$0.4	$21.7	$1.9	$0.1	$1.9	254	134
6	Terminal	Transformer	DEOK	$3.6	$0.0	$3.7	$1.6	$0.0	$1.6	322	17
7	East Bend	Transformer	DEOK	$1.5	$0.0	$1.5	$1.5	$0.0	$1.5	453	0
8	Pierce	Transformer	DEOK	$4.9	$0.0	$4.9	$1.4	$0.0	$1.4	305	0
9	Delaware - Hogan	Line	AEP	$1.2	($0.5)	$0.7	$1.4	($0.1)	$1.3	1,227	235
10	Lakeview - Greenfield	Line	ATSI	($2.5)	($0.9)	($3.4)	$1.6	($0.3)	$1.3	1,356	352
11	Conastone - Peach Bottom	Line	500	$1.5	($0.4)	$1.1	$1.2	$0.0	$1.2	1,100	422
12	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$4.1	($0.0)	$4.1	$1.2	($0.0)	$1.2	285	3
13	Pierce - Beckjord	Flowgate	MISO	$4.7	$0.0	$4.7	$1.0	$0.0	$1.0	263	0
14	Tanners Creek - Miami Fort	Line	AEP	$2.3	($0.2)	$2.1	$1.0	($0.0)	$1.0	673	489
15	5004/5005 Interface	Interface	500	($1.5)	($0.2)	($1.8)	$0.8	$0.0	$0.8	175	47
16	Nottingham	Other	PECO	$0.8	$0.0	$0.8	$0.7	$0.0	$0.7	1,157	390
17	Miami Fort	Transformer	DEOK	$0.9	($0.0)	$0.8	$0.7	($0.0)	$0.7	317	2
18	Bedington - Black Oak	Interface	500	($0.7)	($0.2)	($0.9)	$0.7	$0.0	$0.7	316	52
19	Conastone - Northwest	Line	BGE	$0.5	($0.3)	$0.2	$0.6	($0.0)	$0.6	336	234
20	Hazard	Transformer	AEP	($0.2)	($0.0)	($0.2)	$0.6	$0.0	$0.6	246	17
	Top 20 Total			$65.6	($7.9)	$57.7	$29.4	($0.4)	$29.0	14,992	4,689
	All Other Constraints			$11.6	($2.3)	$9.4	$21.4	($1.7)	$19.7	80,408	18,305
	Total			$77.2	($10.1)	$67.1	$50.8	($2.1)	$48.7	95,400	22,994

DLCO Control Zone

Table 11-47 DLCO Control Zone top congestion cost impacts (By facility): 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	$1.9	($0.6)	$1.3	$1.5	$0.0	$1.6	720	150
2	Cloverdale	Transformer	AEP	$0.8	($0.1)	$0.7	$1.3	$0.0	$1.4	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.1	$0.0	$0.1	$1.2	$0.0	$1.2	1,511	0
4	Lakeview - Greenfield	Line	ATSI	($2.7)	$1.0	($1.7)	$0.8	($0.2)	$0.6	1,356	352
5	Graceton - Safe Harbor	Line	BGE	$0.0	($0.2)	($0.1)	$0.7	($0.1)	$0.6	3,361	2,046
6	Conastone - Peach Bottom	Line	500	$0.1	($0.1)	($0.0)	$0.6	$0.0	$0.6	1,100	422
7	Batesville - Hubble	Flowgate	MISO	$0.0	($0.0)	$0.0	$0.5	$0.0	$0.6	254	134
8	Pleasant View - Ashburn	Line	Dominion	($0.0)	$0.1	$0.0	$0.5	$0.0	$0.5	303	33
9	Wescosville	Transformer	PPL	($0.1)	$0.1	$0.0	$0.4	$0.0	$0.5	553	172
10	Gable Switch Station - South Cadiz	Line	AEP	($0.2)	$0.0	($0.2)	$0.4	($0.0)	$0.4	284	106
11	Maple - Jackson	Line	ATSI	($1.4)	($0.2)	($1.5)	$0.4	($0.0)	$0.4	1,000	155
12	Nottingham	Other	PECO	$0.1	$0.0	$0.1	$0.3	$0.0	$0.3	1,157	390
13	Bedington - Black Oak	Interface	500	$0.5	($0.1)	$0.4	$0.3	$0.0	$0.3	316	52
14	5004/5005 Interface	Interface	500	$1.2	($0.1)	$1.1	$0.3	$0.0	$0.3	175	47
15	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.3	($0.0)	$0.3	814	136
16	Krendale - Shanorma	Line	APS	($0.4)	$0.0	($0.4)	$0.3	$0.0	$0.3	976	0
17	Brunot Island - Collier	Line	DLCO	$1.0	$0.0	$1.0	$0.2	$0.0	$0.3	208	2
18	AP South	Interface	500	$0.3	$0.0	$0.3	$0.2	($0.0)	$0.2	498	37
19	Northport - Albion	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.2	$0.0	$0.2	132	28
20	Yukon	Transformer	500	$0.4	$0.3	$0.7	$0.2	($0.0)	$0.2	102	58
	Top 20 Total			$1.6	$0.3	$1.9	$10.8	($0.2)	$10.6	15,435	4,419
	All Other Constraints			$4.2	$1.2	$5.4	$6.5	($1.0)	$5.5	75,063	18,411
	Total			$5.8	$1.6	$7.4	$17.3	($1.1)	$16.2	90,498	22,830

EKPC Control Zone

Table 11-48 EKPC Control Zone top congestion cost impacts (By facility): 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	$1.5	$1.2	$2.7	$2.4	$0.1	$2.5	720	150
2	Cloverdale	Transformer	AEP	($2.8)	$0.3	($2.4)	$1.5	$0.0	$1.5	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($2.7)	$0.0	($2.7)	$1.5	$0.0	$1.5	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$1.0	$0.4	$1.4	$1.2	($0.1)	$1.1	3,361	2,046
5	Delco Remy - Fall Creek	Line	AEP	($0.3)	$0.1	($0.3)	$0.9	($0.0)	$0.9	247	18
6	Lakeview - Greenfield	Line	ATSI	($0.9)	$0.4	($0.4)	$1.0	($0.2)	$0.8	1,356	352
7	Conastone - Peach Bottom	Line	500	$0.3	$0.1	$0.4	$0.6	$0.0	$0.6	1,100	422
8	Batesville - Hubble	Flowgate	MISO	($11.0)	$0.2	($10.8)	$0.5	$0.0	$0.5	254	134
9	5004/5005 Interface	Interface	500	($0.5)	$0.1	($0.4)	$0.5	$0.0	$0.5	175	47
10	Tanners Creek - Miami Fort	Line	AEP	($0.2)	($0.0)	($0.2)	$0.5	$0.0	$0.5	673	489
11	Bedington - Black Oak	Interface	500	($0.2)	$0.1	($0.1)	$0.4	$0.0	$0.5	316	52
12	AP South	Interface	500	($0.1)	$0.0	($0.1)	$0.4	($0.0)	$0.4	498	37
13	Hazard	Transformer	AEP	($0.4)	$0.3	($0.1)	$0.3	$0.0	$0.4	246	17
14	Broadford - Saltville	Line	AEP	$0.3	($0.3)	$0.1	$0.3	$0.0	$0.4	355	56
15	Northport - Albion	Flowgate	MISO	$0.1	$0.0	$0.1	$0.3	$0.1	$0.3	132	28
16	Conastone - Northwest	Line	BGE	$0.2	$0.0	$0.2	$0.3	$0.0	$0.3	336	234
17	Nottingham	Other	PECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	1,157	390
18	Terminal	Transformer	DEOK	($0.1)	$0.0	($0.1)	$0.3	$0.0	$0.3	322	17
19	Brokaw - Leroy	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.2	$0.1	$0.3	1,232	261
20	Pleasant View - Ashburn	Line	Dominion	($0.0)	($0.1)	($0.1)	$0.2	$0.0	$0.3	303	33
	Top 20 Total			($15.2)	$2.9	($12.3)	$13.8	$0.1	$13.9	14,909	4,882
	All Other Constraints			($1.8)	$1.7	($0.1)	$10.2	($0.8)	$9.5	79,518	18,112
	Total			($17.0)	$4.6	($12.4)	$24.0	($0.7)	$23.4	94,427	22,994

OVEC Control Zone

Table 11-49 OVEC Control Zone top congestion cost impacts (By facility): December, 2018[25]

				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 - Jackson Rd	Line	PSEG	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	213	56
2	Maywood - Saddlebrook	Line	PSEG	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	417	98
3	Unclassified	Unclassified	Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
4	College Corner - Richmond	Line	AEP	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	18	73
5	Dupnt Seaford - Laurel	Line	DPL	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)	0	156
6	Segreto - Palisades	Flowgate	MISO	$0.3	($0.1)	$0.2	$0.0	($0.0)	($0.0)	441	117
7	Monroe - Vineland	Line	AECO	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	2,858	500
8	New Meredith - Church	Line	DPL	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	79
9	Maroa - E GooseCreek	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.0	($0.0)	($0.0)	287	96
10	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	129
11	Big Pine Substation - Kiski Valley	Line	APS	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	251	80
12	Homer City	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	39	9
13	Kent - Vaughn	Line	DPL	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)	504	57
14	Sandburg	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.0	($0.0)	($0.0)	74	66
15	Fargo	Flowgate	MISO	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	1,308	510
16	Marblehead	Flowgate	MISO	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	411	484
17	Farilawn - Waldwick	Line	PSEG	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	11	18
18	West Akron - Brush	Line	ATSI	$0.0	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	241	36
19	Carlisle Pike - Gardners	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	356	14
20	North Champaign - Vermilion	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	63	28
	Top 20 Total			$0.2	($0.4)	($0.1)	($0.0)	$0.0	$0.0	7,492	2,606
	All Other Constraints			$0.2	$0.2	$0.3	$0.0	($0.0)	($0.0)	35,074	8,662
	Total			$0.4	($0.2)	$0.2	($0.0)	$0.0	$0.0	42,566	11,268

25 In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.)

South Region Congestion-Event Summaries

Dominion Control Zone

Table 11-50 Dominion Control Zone top congestion cost impacts (By facility): 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	$11.9	($2.3)	$9.6	$23.9	$0.7	$24.6	720	150
2	Cloverdale	Transformer	AEP	$11.5	$1.1	$12.6	$14.5	$0.3	$14.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.2)	$0.0	($0.2)	$9.2	$0.0	$9.2	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$8.7	($2.2)	$6.5	$10.1	($0.9)	$9.2	3,361	2,046
5	Pleasant View - Ashburn	Line	Dominion	$29.1	$1.1	$30.2	$6.2	$0.1	$6.4	303	33
6	Conastone - Peach Bottom	Line	500	$0.3	$0.0	$0.3	$5.0	$0.1	$5.1	1,100	422
7	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.1	$0.0	$4.5	$0.4	$4.9	254	134
8	5004/5005 Interface	Interface	500	$0.8	$0.1	$1.0	$4.5	$0.1	$4.6	175	47
9	AP South	Interface	500	$6.7	($0.1)	$6.6	$4.1	($0.0)	$4.1	498	37
10	Bedington - Black Oak	Interface	500	$4.3	($0.2)	$4.1	$4.0	$0.1	$4.1	316	52
11	Gardners - Texas East	Line	Met-Ed	$0.3	($0.1)	$0.3	$3.2	$0.1	$3.3	2,788	439
12	Conastone - Northwest	Line	BGE	$0.6	$0.3	$0.8	$3.0	$0.0	$3.0	336	234
13	Person - Sedge Hill	Line	Dominion	$5.6	($0.4)	$5.1	$2.7	($0.1)	$2.7	814	136
14	Nottingham	Other	PECO	$1.5	$0.0	$1.5	$2.6	$0.0	$2.6	1,157	390
15	Northport - Albion	Flowgate	MISO	$0.2	($0.0)	$0.2	$1.9	$0.3	$2.2	132	28
16	Maple - Jackson	Line	ATSI	($0.7)	$0.1	($0.6)	$2.4	($0.1)	$2.2	1,000	155
17	Brokaw - Leroy	Flowgate	MISO	$0.5	($0.2)	$0.4	$1.2	$0.7	$1.9	1,232	261
18	Broadford - Saltville	Line	AEP	($0.1)	$0.1	$0.1	$1.8	$0.0	$1.9	355	56
19	Bagley - Graceton	Line	BGE	$0.2	($0.2)	($0.0)	$1.8	($0.1)	$1.8	595	214
20	Wescosville	Transformer	PPL	$0.1	$0.1	$0.2	$1.6	$0.2	$1.7	553	172
	Top 20 Total			$81.2	($2.6)	$78.7	$108.2	$2.1	$110.3	17,815	5,105
	All Other Constraints			$24.2	($0.4)	$23.9	$50.7	($8.8)	$41.8	80,388	18,112
	Total			$105.5	($2.9)	$102.5	$158.9	($6.8)	$152.1	98,203	23,217

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 December 31, 2018, PJM had 137 flowgates eligible for M2M (Market to Market) coordination and MISO had 239 flowgates eligible for M2M coordination.

Table 11-51 and Table 11-52 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 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 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 11-51 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 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	($20.8)	($94.1)	($2.9)	$70.4	$0.0	$0.0	$0.0	$0.0	$70.4	1,511	0
2	Batesville - Hubble	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$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	Quad Cities - Cordova	($5.6)	($12.4)	$2.6	$9.4	$0.0	$0.0	$0.0	$0.0	$9.4	1,522	0
7	Flint Lake - Luchtman Road	$0.2	($10.6)	($4.9)	$5.8	($0.2)	($1.4)	$1.8	$3.0	$8.8	890	365
8	Olive	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	445	0
9	Pierce - Beckjord	($2.2)	($9.1)	($0.1)	$6.7	$0.0	$0.0	$0.0	$0.0	$6.7	263	0
10	Volunteer - Phipps Bend	($0.3)	($2.9)	($0.7)	$1.9	($1.0)	($3.2)	$1.1	$3.4	$5.3	7	38
11	Burnham - Munster	$0.6	($4.5)	$0.2	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	923	0
12	Segreto - Palisades	($0.2)	($6.0)	$0.6	$6.4	($0.1)	$0.1	($1.4)	($1.7)	$4.7	441	117
13	Plymouth - Leesburg	($1.9)	($7.7)	($2.0)	$3.7	($0.5)	$0.4	$1.5	$0.6	$4.4	306	163
14	Greentown	($0.0)	($0.8)	($0.2)	$0.6	($0.9)	$6.0	$2.0	($4.8)	($4.2)	151	72
15	Michigan City - Bosserman	($0.8)	($5.5)	($0.6)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	809	0
16	Braidwood - East Frankfurt	($0.0)	($3.9)	($0.0)	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	74	0
17	Holland - Neoga	($0.6)	($4.3)	($0.1)	$3.5	$0.2	$0.0	$0.0	$0.2	$3.7	106	41
18	Northwest Tap - Purdue	($1.9)	($6.5)	($1.1)	$3.5	$1.1	$2.3	$1.3	$0.1	$3.6	477	242
19	Eugene - Cayuga	($0.4)	($4.4)	($0.6)	$3.4	$0.0	$0.0	($0.0)	($0.0)	$3.4	293	23
20	Roxana - Praxair	$2.8	($4.4)	($4.2)	$3.0	$3.2	$2.2	($7.2)	($6.2)	($3.2)	1,132	481
	Top 20 Total	($47.1)	($282.0)	($32.9)	$202.0	$1.6	$1.9	$3.8	$3.5	$205.6	11,913	1,965
	All Other Constraints	($9.0)	($57.0)	($3.5)	$44.4	$0.3	$5.4	($6.7)	($11.7)	$32.7	7,937	3,612
	Total	($56.1)	($338.9)	($36.4)	$246.5	$2.0	$7.3	($2.9)	($8.2)	$238.2	19,850	5,577

Table 11-52 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2017

		Congestion Costs (Millions)										
		Day-Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Westwood	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	3,399	198
2	Alpine - Belvidere	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	339	0
3	Lake George - Aetna	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.9	$2.7	$9.1	483	244
4	Batesville - Hubble	($5.5)	($19.4)	($4.5)	$9.4	($0.1)	($1.3)	($1.7)	($0.5)	$8.9	379	158
5	Byron - Cherry Valley	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	347	0
6	Brokaw - Leroy	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1,744	528
7	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.9)	($0.5)	$0.4	$0.0	$5.6	425	248
8	Havana E - Havana S	($2.6)	($8.3)	($0.2)	$5.5	$0.0	$0.0	$0.0	$0.0	$5.5	2,260	0
9	Dresden	($0.3)	($4.8)	($0.2)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1,216	0
10	Nelson	($2.2)	($6.6)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	534	0
11	Shadelnd - Lafaysouth	($4.4)	($7.7)	$0.2	$3.5	$6.7	$4.7	($2.3)	($0.3)	$3.1	1,055	669
12	Nucor - Whitestown	($0.8)	($5.1)	($1.1)	$3.2	$0.1	$0.1	($0.1)	($0.1)	$3.1	519	19
13	Roxana - Praxair	($0.1)	$0.4	($0.5)	($1.0)	$1.4	$0.0	($3.4)	($2.0)	($3.0)	1,734	290
14	Todd Hunter	($0.6)	($3.6)	($0.0)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	988	0
15	Burnham - Munster	$0.2	($2.3)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	760	0
16	Quad Cities	($1.3)	($3.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	460	0
17	Pleasant Prairie - Zion	($0.6)	($3.3)	($0.1)	$2.7	$0.0	$0.1	($0.2)	($0.2)	$2.4	2,052	395
18	Olive - Bosserman	$1.2	($1.5)	($0.4)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	133	0
19	Havana South - Mason City West	($0.6)	($2.1)	$0.1	$1.6	$0.2	($0.3)	($0.0)	$0.4	$2.0	753	181
20	Reynolds - Magnetation	($0.3)	($1.9)	$0.4	$2.0	$0.0	($0.1)	($0.1)	($0.0)	$2.0	297	31
	Top 20 Total	($44.6)	($158.8)	($12.9)	$101.2	$6.6	$4.8	$0.6	$2.4	$103.6	19,877	2,961
	All Other Constraints	($6.2)	($46.0)	($11.7)	$28.1	$0.4	$0.8	($3.7)	($4.2)	$23.9	9,735	2,676
	Total	($50.9)	($204.8)	($24.6)	$129.3	$7.0	$5.7	($3.1)	($1.8)	$127.5	29,612	5,637

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 2018, none of the NYISO flowgates were binding and only one flowgate was binding in 2017. Table 11-53 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2017.

Table 11-53 Congestion cost impact from NYISO flowgates affecting PJM dispatch (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Central East	Flowgate	NYISO	($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332
	Total			($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332

Congestion Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-54 and Table 11-55 show the 500 kV constraints affecting congestion costs in PJM for 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 11-54 Regional constraints summary (By facility): 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	$55.6	($66.9)	($5.3)	$117.2	$13.4	$18.7	$9.0	$3.8	$121.0	720	150
2	5004/5005 Interface	Interface	($15.4)	($54.4)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	175	47
3	Conastone - Peach Bottom	Line	$29.8	$0.7	($0.2)	$28.9	$1.6	$0.8	($0.0)	$0.7	$29.6	1,100	422
4	Bedington - Black Oak	Interface	$10.2	($14.0)	($1.4)	$22.7	$0.6	$0.7	$0.6	$0.5	$23.2	316	52
5	AP South	Interface	$14.1	($8.3)	($1.6)	$20.8	$0.1	$0.1	($0.0)	($0.0)	$20.8	498	37
6	Yukon	Transformer	($2.6)	($9.7)	$0.3	$7.4	$0.6	$0.8	($0.5)	($0.7)	$6.8	102	58
7	CPL - DOM	Interface	$6.1	($1.2)	$0.8	$8.0	$0.3	$1.5	($0.4)	($1.6)	$6.4	272	98
8	West	Interface	($1.4)	($6.2)	($0.8)	$4.0	$0.0	($0.0)	($0.0)	($0.0)	$4.0	74	11
9	East	Interface	($2.3)	($5.9)	($0.1)	$3.5	($0.0)	$0.0	($0.1)	($0.1)	$3.4	107	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		$89.4	($179.7)	($12.9)	$256.2	$17.5	$24.2	$10.4	$3.6	$259.8	3,977	1,294
	All Other Constraints		($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	18	5
	Total		$89.4	($179.8)	($12.9)	$256.3	$17.5	$24.2	$10.4	$3.6	$259.9	3,995	1,299

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 11-55 Regional constraints summary (By facility): 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	$38.7	$1.6	$0.1	$37.2	$1.7	$1.2	$1.6	$2.0	$39.3	3,159	840
2	5004/5005 Interface	Interface	($9.9)	($38.7)	($3.8)	$25.0	$4.5	$11.4	$4.6	($2.4)	$22.7	173	105
3	AP South	Interface	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	1,315	75
4	Three Mile Island	Transformer	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.5)	$0.9	$1.3	$13.3	540	86
5	Bedington - Black Oak	Interface	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1,215	62
6	AEP - DOM	Interface	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.4	$0.2	$0.3	$7.8	948	32
7	West	Interface	($0.4)	($2.1)	($0.2)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	180	0
8	Limerick	Transformer	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	142	5
9	Conastone	Transformer	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	33	2
10	Cabot - Keystone	Line	($0.1)	($0.5)	$0.1	$0.5	$0.1	$0.2	($0.0)	($0.2)	$0.3	97	18
11	East	Interface	($0.5)	($1.1)	($0.1)	$0.6	$0.2	$0.7	$0.2	($0.3)	$0.3	131	10
12	Belmont	Transformer	($0.0)	($0.2)	($0.1)	$0.1	$0.0	$0.1	($0.3)	($0.4)	($0.3)	42	52
13	Keeney - Rockspring	Line	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	39	0
14	502 Junction	Transformer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	42	0
15	Bristers - Ox	Line	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
16	Redlion	Transformer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	55	0
17	Central	Interface	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
18	Elroy - Hosensack	Line	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
19	Cabot	Other	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
20	Hope Creek - Red Lion	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
	Top 20 Total		$59.3	($65.8)	($6.8)	$118.3	$6.9	$15.2	$8.5	$0.2	$118.4	8,157	1,287
	All Other Constraints		$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	62	1
	Total		$59.3	($65.8)	($6.8)	$118.3	$6.9	$15.2	$8.5	$0.2	$118.5	8,219	1,288

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 $9.1 million in net congestion credits in 2018 and received $18.2 million in net congestion credits in 2017 (Table 11-56 and Table 11-57). Physical entities paid $1,319.0 million in congestion charges in 2018 and $715.8 million in congestion charges in 2017.

Table 11-56 Congestion cost by type of participant: 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	$48.9	($2.6)	($36.9)	$14.6	($31.9)	$5.7	$13.9	($23.8)	($0.0)	($9.1)
Physical	$300.3	($1,045.9)	$18.0	$1,364.3	$43.4	$56.3	($32.4)	($45.3)	$0.0	$1,319.0
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-57 Congestion cost by type of participant: 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	$19.5	$14.6	($18.3)	($13.4)	($11.7)	($7.9)	($0.9)	($4.8)	$0.0	($18.2)
Physical	$168.0	($568.7)	$9.8	$746.5	$33.9	$55.0	($9.5)	($30.7)	$0.0	$715.8
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

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 as a result of a FERC order, and increased after December 7, 2015 when UTC activity increased, as a result of a FERC order. Figure 11-5 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined, as a result of a FERC order.

In 2018, the average hourly UTC submitted MW decreased by 57.3 percent and UTC cleared MW decreased 48.7 percent, compared to 2017. Day-ahead congestion event hours decreased by 55.9 percent from 300,923 congestion event hours in 2017 to 132,598 congestion event hours in 2018 (Table 11-22). Day-ahead congestion event hours decreased by 64.8 percent from 250,535 congestion event hours for the period February 22, 2017, through December 31, 2017, to 88,078 congestion event hours for the period February 22, 2018 through December 31, 2018.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through December 31, 2018.

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

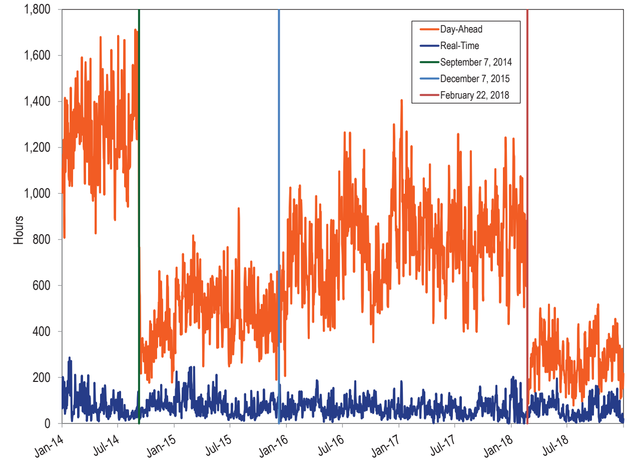
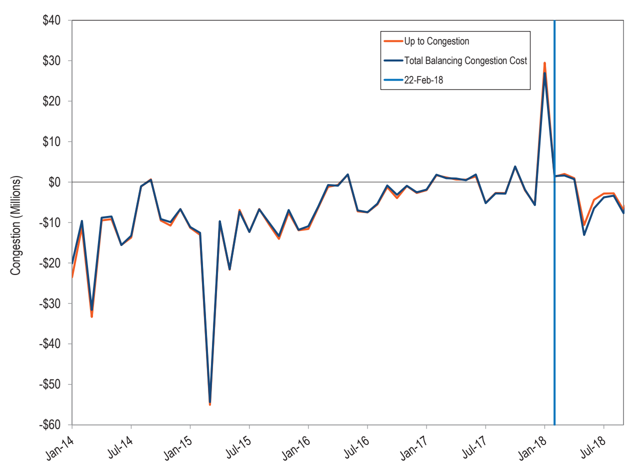


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014, through December 31, 2018. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January 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.

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



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

Balancing congestion is caused by settling real time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences that exist between the day-ahead and real-time market models including modeled constraints, transfer capability (line limits) of the modeled 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 among 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, which means a decrease in congestion. 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 11-58 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.

As a result of the fact that the transmission capability between A and B is 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 price 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 11-58 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, under the recent FERC order.

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 11-58 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-Ahead 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 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.

31 PJM Operating Agreement Schedule 1 §3.7.
32 *Id.*
33 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25. 2018)

- **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 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 2018 was $960.1 million, which was comprised of load loss payments of -$70.6 million, generation loss credits of -$1,042.7 million, explicit loss costs of -$11.9 million and inadvertent loss charges of $0.0 million (Table 11-60).

Monthly marginal loss costs in 2018 ranged from $49.5 million in February to $222.8 million in January. Total marginal loss surplus increased in 2018 by $105.6 million or 49.2 percent from $214.6 million in 2017 to $320.2 million in 2018.

Table 11-59 shows the total marginal loss component costs and the total PJM billing for 2008 through 2018.

Table 11-59 Total PJM loss component costs (Dollars (Millions)): 2008 through 2018[35]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,306	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%

Table 11-60 shows PJM total marginal loss costs by accounting category for 2008 through 2018. Table 11-61 shows PJM total marginal loss costs by accounting category by market for 2008 through 2018.

34 PJM Operating Agreement Schedule 1 §3.7.
35 The loss costs include net inadvertent charges.

Table 11-60 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2018

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($70.6)	($1,042.7)	($11.9)	$0.0	$960.1

Table 11-61 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($76.7)	($1,032.2)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.1)	$0.0	$960.1

Table 11-62 and Table 11-63 show the total loss costs for each transaction type in 2018 and 2017. In 2018, generation paid loss costs of $976.7 million, 101.7 percent of total loss costs. In 2017, generation paid loss costs of $731.9 million, 105.9 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 2018, DECs were paid $2.0 million in loss credits in the day-ahead market, paid $2.7 million in loss costs in the balancing energy market and paid $0.7 million in total loss payments. In 2018, INCs paid $13.6 million in loss costs in the day-ahead market, were paid $15.0 million in loss credits in the balancing energy market and were paid $1.4 million in total loss credits. In 2018, up to congestion paid $42.3 million in loss costs in the day-ahead market, were paid $53.3 million in loss credits in the balancing energy market and received $11.0 million in total loss credits.

Table 11-62 Total PJM loss costs by transaction type by market (Dollars (Millions)): 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	($2.0)	$0.0	$0.0	($2.0)	$2.7	$0.0	$0.0	$2.7	$0.0	$0.7
Demand	($7.6)	$0.0	$0.0	($7.6)	$12.2	$0.0	$0.0	$12.2	$0.0	$4.5
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($24.6)	$0.0	$0.0	($24.6)	($9.3)	$0.0	$0.4	($8.9)	$0.0	($33.5)
Generation	$0.0	($973.2)	$0.0	$973.2	$0.0	($3.5)	$0.0	$3.5	$0.0	$976.7
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	($3.4)	$0.0	$3.4	$0.0	($22.5)	($0.5)	$22.1	$0.0	$25.5
INC	$0.0	($13.6)	$0.0	$13.6	$0.0	$15.0	$0.0	($15.0)	$0.0	($1.4)
Internal Bilateral	($14.0)	($13.6)	$0.5	$0.0	$0.5	$0.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$42.3	$42.3	$0.0	$0.0	($53.3)	($53.3)	$0.0	($11.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.1)	$0.0	$960.1

Table 11-63 Total PJM loss costs by transaction type by market (Dollars (Millions)): 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	($7.7)	$0.0	$0.0	($7.7)	$6.0	$0.0	$0.0	$6.0	$0.0	($1.7)
Demand	($5.6)	$0.0	$0.0	($5.6)	$11.4	$0.0	$0.0	$11.4	$0.0	$5.8
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($17.3)	$0.0	$0.1	($17.2)	($7.8)	$0.0	$0.8	($7.0)	$0.0	($24.3)
Generation	$0.0	($730.0)	$0.0	$730.0	$0.0	($1.9)	$0.0	$1.9	$0.0	$731.9
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.9)
Import	$0.0	($1.9)	$0.0	$1.9	$0.0	($11.5)	($0.3)	$11.2	$0.0	$13.1
INC	$0.0	($13.8)	$0.0	$13.8	$0.0	$12.0	$0.0	($12.0)	$0.0	$1.8
Internal Bilateral	($21.6)	($21.5)	$0.1	$0.0	$1.7	$1.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$54.9	$54.9	$0.0	$0.0	($90.0)	($90.0)	$0.0	($35.1)
Wheel In	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.3
Total	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.9

Monthly Marginal Loss Costs

Table 11-64 shows a monthly summary of marginal loss costs by market type for 2017 and 2018.

Table 11-64 Monthly marginal loss costs by market (Millions): 2017 and 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	$65.0	($3.0)	($0.0)	$62.1
Nov	$55.3	($4.0)	$0.0	$51.3	$77.6	($5.4)	($0.0)	$72.2
Dec	$96.8	($5.3)	$0.0	$91.5	$73.7	($4.8)	($0.0)	$68.9
Total	$769.9	($79.1)	$0.0	$690.8	$997.2	($37.1)	$0.0	$960.1

Figure 11-7 shows PJM monthly marginal loss costs for 2008 through 2018.

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

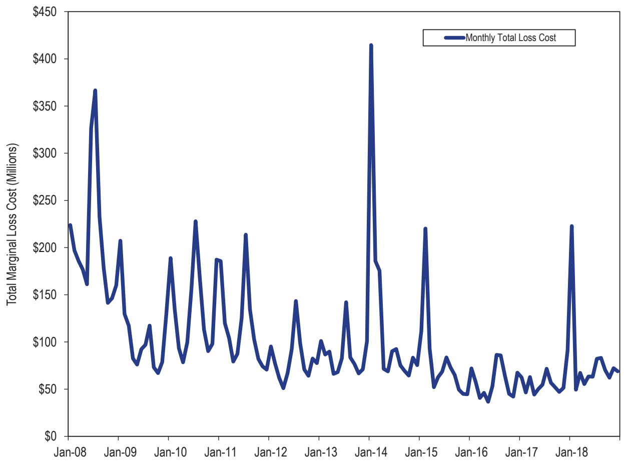


Table 11-65 and Table 11-66 show the monthly total loss costs for each virtual transaction type in 2018 and 2017.

Table 11-65 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 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)
Oct	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.1)	$3.3	($4.0)	($0.7)	($0.6)
Nov	($0.0)	$0.2	$0.1	$1.5	($1.6)	($0.1)	$5.4	($6.5)	($1.1)	($1.1)
Dec	($0.2)	$0.4	$0.1	$0.7	($0.9)	($0.2)	$4.6	($5.8)	($1.3)	($1.3)
Total	($2.0)	$2.7	$0.7	$13.6	($15.0)	($1.4)	$42.3	($53.3)	($11.0)	($11.8)

Table 11-66 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)	($4.4)	($4.4)
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	$3.8	($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 11-67 Marginal loss surplus (Dollars (Millions)): 2008 through 2018[36]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustment			
	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	$0.0	($0.7)	($0.0)	$639.7
2010	($797.9)	$1,634.8	$0.1	$0.7	($0.0)	$836.4
2011	($793.8)	$1,379.5	$0.1	($1.0)	$0.1	$586.7
2012	($593.0)	$981.7	$0.0	$2.0	($0.0)	$386.7
2013	($687.6)	$1,035.3	$0.1	$3.0	($0.0)	$344.8
2014	($977.7)	$1,466.1	($0.0)	$6.3	$0.1	$482.1
2015	($627.4)	$968.7	($0.0)	$5.1	($0.1)	$336.3
2016	($466.3)	$696.5	($0.0)	$3.2	($0.2)	$227.2
2017	($475.2)	$690.8	$0.0	$1.1	($0.1)	$214.6
2018	($636.7)	$960.1	($0.0)	$3.2	($0.1)	$320.2

Table 11-67 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for 2008 through 2018. The total marginal loss surplus increased $105.6 million in 2018 from 2017.

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 2018 was -$636.7 million, which was comprised of load energy payments of $43,803.7 million, generation energy credits of $44,445.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of $4.6 million. The monthly energy costs for 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 11-68 shows total energy component costs and total PJM billing, for 2008 through 2018. The total energy component costs are net energy costs.

Table 11-68 Total PJM energy component costs (Dollars (Millions)): 2008 through 2018[37]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,306	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)

Energy costs for 2008 through 2018 are shown in Table 11-69 and Table 11-70. Table 11-69 shows PJM energy costs by accounting category and Table 11-70 shows PJM energy costs by market category.

Table 11-69 Total PJM energy costs by accounting category (Dollars (Millions)): 2008 through 2018

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,803.7	$44,445.1	$0.0	$4.6	($636.7)

Table 11-70 Total PJM energy costs by market category (Dollars (Millions)): 2008 through 2018

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,947.9	$44,658.9	$0.0	($711.0)	($144.1)	($213.8)	$0.0	$69.7	$4.6	($636.7)

Table 11-71 and Table 11-72 show the total energy costs for each transaction type in 2018 and 2017. In 2018, generation was paid $31,247.1 million and demand paid $30,094.5 million in net energy payment. In 2017, generation was paid $24,566.8 million and demand paid $23,484.2 million in net energy payment.

37 The energy costs include net inadvertent charges.

Table 11-71 Total PJM energy costs by transaction type by market (Dollars (Millions)): 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	$1,010.9	$0.0	$0.0	$1,010.9	($1,019.5)	$0.0	$0.0	($1,019.5)	($8.6)
Demand	$29,631.7	$0.0	$0.0	$29,631.7	$462.9	$0.0	$0.0	$462.9	$30,094.5
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	$0.0
Export	$858.4	$0.0	$0.0	$858.4	$386.7	$0.0	$0.0	$386.7	$1,245.1
Generation	$0.0	$31,211.7	$0.0	($31,211.7)	$0.0	$35.3	$0.0	($35.3)	($31,247.1)
Import	$0.0	$139.1	$0.0	($139.1)	$0.0	$579.1	$0.0	($579.1)	($718.2)
INC	$0.0	$860.1	$0.0	($860.1)	$0.0	($853.0)	$0.0	$853.0	($7.1)
Internal Bilateral	$12,448.0	$12,448.0	$0.0	($0.0)	$14.8	$14.8	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$9.9	$0.0	($9.9)	($9.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$9.9	$0.0	$0.0	$9.9	$9.9
Total	$43,947.9	$44,658.9	$0.0	($711.0)	($144.1)	($213.8)	$0.0	$69.7	($641.3)

Table 11-72 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2017

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,092.8	$0.0	$0.0	$1,092.8	($1,095.6)	$0.0	$0.0	($1,095.6)	($2.9)
Demand	$23,433.7	$0.0	$0.0	$23,433.7	$50.5	$0.0	$0.0	$50.5	$23,484.2
Demand Response	($0.6)	$0.0	$0.0	($0.6)	$0.6	$0.0	$0.0	$0.6	($0.0)
Export	$707.1	$0.0	$0.0	$707.1	$346.6	$0.0	$0.0	$346.6	$1,053.6
Generation	$0.0	$24,616.7	$0.0	($24,616.7)	$0.0	($50.0)	$0.0	$50.0	($24,566.8)
Import	$0.0	$81.2	$0.0	($81.2)	$0.0	$361.0	$0.0	($361.0)	($442.2)
INC	$0.0	$1,183.6	$0.0	($1,183.6)	$0.0	($1,175.3)	$0.0	$1,175.3	($8.2)
Internal Bilateral	$10,257.2	$10,257.2	$0.0	$0.0	$359.9	$359.9	$0.0	$0.0	$0.0
Total	$35,490.1	$36,138.8	$0.0	($648.7)	($338.0)	($504.4)	$0.0	$166.4	($482.3)

Monthly Energy Costs

Table 11-73 shows a monthly summary of energy costs by market type for 2017 and 2018. Marginal total energy costs in 2018 decreased from 2017. Monthly total energy costs in 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Table 11-73 Monthly energy costs by market type (Dollars (Millions)): 2017 and 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)	($47.2)	$4.5	($0.6)	($43.2)
Nov	($45.4)	$9.7	$0.1	($35.5)	($57.2)	$9.8	($0.2)	($47.6)
Dec	($75.1)	$12.4	$0.8	($61.9)	($55.2)	$8.3	($0.4)	($47.2)
Total	($648.5)	$166.2	$7.1	($475.2)	($711.0)	$69.7	$4.6	($636.7)

Figure 11-8 shows PJM monthly energy costs for 2008 through 2018.

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

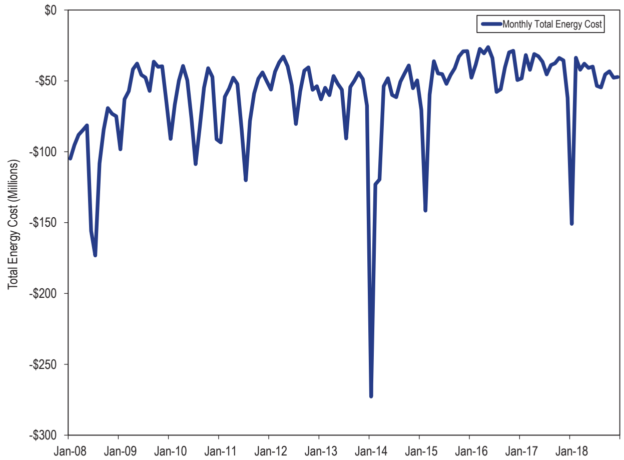


Table 11-74 and Table 11-75 show the monthly total energy costs for each virtual transaction type in 2018 and year of 2017. In 2018, DECs paid $1,010.9 million in energy costs in the day-ahead market, were paid $1,019.5 million in energy credits in the balancing energy market and were paid $8.6 million in total energy credits. In 2018, INCs were paid $860.1 million in energy credits in the day-ahead market, paid $853.0 million in energy costs in the balancing market and were paid $7.1 million in total energy credits. In 2017, DECs paid $1,092.8 million in energy costs in the day-ahead market, were paid $1,095.6 million in energy credits in the balancing energy market and were paid $2.9 million in total energy credits. In 2017, INCs were paid $1,183.6 million in energy credits in the day-ahead market, paid $1,175.3 million in energy cost in the balancing energy market and received $8.2 million in total energy credits.

Table 11-74 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 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)
Oct	$86.7	($82.4)	$4.3	($85.8)	$82.1	($3.7)	$0.6
Nov	$83.1	($80.9)	$2.2	($88.9)	$86.6	($2.3)	($0.2)
Dec	$79.0	($78.4)	$0.6	($60.8)	$59.2	($1.6)	($1.0)
Total	$1,010.9	($1,019.5)	($8.6)	($860.1)	$853.0	($7.1)	($15.7)

Table 11-75 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)