Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum of three components: the system marginal price (SMP) or energy component, the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[1] SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.

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

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

MLMP is the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.[2]

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[3] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $611.1 million or 214.0 percent, from $285.5 million in the first six months of 2017 to $896.6 million in the first six months of 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $619.7 million or 208.8 percent, from $296.8 million in the first six months of 2017 to $916.5 million in the first six months of 2018.

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June 2013 through 2014.

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

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

4 The total congestion and marginal losses were calculated as of July 16, 2018, and are subject to change, based on continued PJM billing updates.

- **Balancing Congestion.** Negative balancing congestion costs increased by $8.6 million or 76.3 percent, from -$11.3 million in the first six months of 2017 to -$19.9 million in the first six months of 2018. Balancing explicit costs increased by $7.1 million or 170.0 percent, from $4.1 million in the first six months of 2017 to $11.2 million in the first six months of 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $755.4 million or 263.3 percent, from $286.8 million in the first six months of 2017 to $1,042.2 million in the first six months of 2018.
- **Monthly Congestion.** Monthly total congestion costs in the first six months of 2018 ranged from $45.2 million in February to $535.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AEP - DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the Tanners Creek - Miami Fort Flowgate, and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first six months of 2018. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  But day-ahead congestion frequency decreased by 46.7 percent from 153,062 congestion event hours in the first six months of 2017 to 81,555 congestion event hours in the first six months of 2018 as a result of a significant decrease in up to congestion transaction (UTC) activities in response to the February 20, 2018, FERC order that limited UTC trading, effective February 22, 2018, to hubs, residual metered load, and interfaces.[5]

  Real-time congestion frequency increased by 11.3 percent from 11,437 congestion event hours in the first six months of 2017 to 12,728 congestion event hours in the first six months of 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 the first six months of 2018. With $118.3 million in total congestion costs, it accounted for 13.2 percent of the total PJM congestion costs in the first six months of 2018.
- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2018. AEP had $277.6 million in total congestion costs, comprised of -$81.3 million in total load congestion payments, -$359.5 million in total generation congestion credits and -$0.6 million in explicit congestion costs. The AEP - DOM Interface, the Cloverdale Transformer, the Capitol Hill - Chemical Line, the Tanners Creek - Miami Fort Flowgate and the 5004/5005 Interface contributed $171.4 million, or 61.7 percent of the total AEP control zone congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $200.8 million or 62.6 percent, from $320.6 million in the first six months of 2017 to $521.4 million in the first six months of 2018. The loss MWh in PJM increased by 485.0 GWh or 6.8 percent, from 7,172.9 GWh in the first six months of 2017 to 7,657.9 GWh in the first six months of 2018. The loss component of real-time LMP in the first six months of 2018 was $0.02, compared to $0.01 in the first six months of 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2018 ranged from $49.5 million in February to $222.8 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $169.7 million or 46.5 percent, from $364.7 million in the first six months of 2017 to $534.4 million in the first six months of 2018.

5 162 FERC ¶ 61,139.

- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $31.1 million or 70.6 percent, from -$44.0 million in the first six months of 2017 to -$12.9 million in the first six months of 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in the first six months of 2018 by $76.8 million or 78.2 percent, from $98.2 million in the first six months of 2017, to $175.0 million in the first six months of 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $123.0 million or 55.3 percent, from -$222.2 million in the first six months of 2017 to -$345.2 million in the first six months of 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $57.9 million or 17.9 percent, from -$322.5 million in the first six months of 2017 to -$380.4 million in the first six months of 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $69.1 million or 69.5 percent, from $99.4 million in the first six months of 2017 to $30.3 million in the first six months of 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Conclusion

Congestion is defined to be the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

The total congestion cost in the first six months of 2018 increased significantly from the first six months of 2017 and was more than the total congestion cost of the entire year of 2017. The increase was a result of an increase in day-ahead congestion cost 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 costs increased by $7.1 million or 170.0 percent, from $4.1 million in the first six months of 2017 to $11.2 million in the first six months of 2018. The increase in balancing explicit costs was the result of an increase in balancing explicit congestion caused by up to congestion (UTCs) which went from $3.5 million in the first six months of 2017 to $18.8 million in the first six months of 2018.

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

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

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8, 86.5 and 98.1 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016 and 2016/2017 planning periods. For the 2017/2018 planning period ARRs and self scheduled FTRs offset 50.7 percent of total congestion costs.

Locational Marginal Price (LMP)

Components

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

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is the sum of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[6] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[7] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area.

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

The load-weighted average real-time LMP increased $12.63 or 42.4 percent from $29.81 in the first six months of 2017 to $42.44 in the first six months of 2018. The load-weighted average congestion component increased by $0.02 from $0.02 in the first six months of 2017 to $0.04 in the first six months of 2018. The load-weighted average loss component in the first six months of 2018 was $0.02 compared to $0.01 in the first six months of 2017. The load-weighted average energy component increased by $12.59 or 42.3 percent from $29.78 in the first six months of 2017 to $42.37 in the first six months of 2018.

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

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

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

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

(Jan - Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$74.77	$74.66	$0.07	$0.05
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02
2014	$69.92	$69.95	($0.06)	$0.02
2015	$42.30	$42.24	$0.03	$0.02
2016	$27.09	$27.04	$0.03	$0.01
2017	$29.81	$29.78	$0.02	$0.01
2018	$42.44	$42.37	$0.04	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for January through June, 2008 through 2018.[10] The load-weighted average day-ahead LMP increased $10.95, or 36.5 percent, from $30.02 in the first six months of 2017 to $40.96 in the first six months of 2018. The load-weighted average congestion component increased $0.09 from $0.02 in the first six months of 2017 to $0.11 in the first six months of 2018. The load-weighted average loss component increased from -$0.02 in the first six months of 2017 to -$0.01 in the first six months of 2018. The load-weighted average energy component increased $10.85, or 36.1 percent, from $30.02 in the first six months of 2017 to $40.86 in the first six months of 2018.

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

(Jan - Jun)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$73.71	$74.10	($0.16)	($0.23)
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	($0.00)
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.84	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00
2014	$70.66	$70.37	$0.30	($0.01)
2015	$43.26	$42.95	$0.33	($0.02)
2016	$27.33	$27.22	$0.12	($0.01)
2017	$30.02	$30.02	$0.02	($0.02)
2018	$40.96	$40.86	$0.11	($0.01)

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

Table 11-3 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2017 through June 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		
Aug	$28.39	$24.66		
Sep	$33.79	$21.28		
Oct	$28.69	$29.20		
Nov	$29.43	$23.26		
Dec	$44.60	$24.74		
Avg	$31.81	$24.42	$45.38	$23.14

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

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

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for the first six months of 2017 and 2018. In the first six months of 2018, BGE had the highest real-time congestion component of all control zones, $6.80, and ComEd had the lowest real-time congestion component, -$9.15.

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

	2017 (Jan - Jun)				2018 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$28.68	$29.81	($1.60)	$0.46	$40.49	$41.77	($2.32)	$1.05
AEP	$29.20	$29.66	($0.09)	($0.37)	$41.23	$42.27	($0.38)	($0.67)
APS	$29.94	$29.78	$0.07	$0.09	$44.74	$42.73	$1.69	$0.33
ATSI	$30.14	$29.57	$0.07	$0.49	$43.91	$41.20	$2.36	$0.35
BGE	$32.91	$30.03	$1.78	$1.10	$52.10	$43.65	$6.80	$1.65
ComEd	$27.61	$29.54	($0.72)	($1.22)	$29.33	$40.90	($9.15)	($2.42)
DAY	$29.80	$29.70	($0.26)	$0.35	$41.76	$41.92	($0.67)	$0.51
DEOK	$28.67	$29.69	($0.21)	($0.82)	$43.29	$42.06	$2.40	($1.17)
DLCO	$29.59	$29.66	$0.04	($0.11)	$43.94	$41.46	$2.52	($0.03)
Dominion	$31.77	$30.05	$1.33	$0.39	$51.20	$44.06	$6.43	$0.71
DPL	$30.92	$30.08	$0.04	$0.80	$47.14	$44.06	$0.77	$2.31
EKPC	$28.57	$29.99	($0.57)	($0.85)	$38.69	$44.90	($4.57)	($1.63)
JCPL	$30.10	$30.05	($0.40)	$0.44	$41.37	$42.06	($1.73)	$1.04
Met-Ed	$30.09	$29.80	($0.06)	$0.35	$41.10	$42.22	($1.85)	$0.72
PECO	$28.97	$29.85	($1.05)	$0.17	$41.24	$42.37	($1.91)	$0.78
PENELEC	$29.36	$29.56	($0.50)	$0.30	$41.30	$41.48	($0.63)	$0.45
Pepco	$31.87	$30.02	$1.12	$0.73	$50.27	$43.35	$5.79	$1.13
PPL	$29.32	$29.80	($0.65)	$0.17	$40.39	$42.62	($2.67)	$0.44
PSEG	$29.88	$29.78	($0.32)	$0.42	$40.93	$41.46	($1.54)	$1.01
RECO	$30.25	$30.07	($0.29)	$0.47	$40.42	$41.41	($1.86)	$0.86
PJM	$29.81	$29.78	$0.02	$0.01	$42.44	$42.37	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-5 for January through June, 2017 and 2018. In the first six months of 2018, BGE had the highest day-ahead congestion component of all control zones, $6.68, and ComEd had the lowest day-ahead congestion component, -$9.15.

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

	2017 (Jan - Jun)				2018 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$28.73	$30.05	($1.49)	$0.16	$39.91	$40.45	($1.05)	$0.51
AEP	$29.64	$29.96	($0.02)	($0.30)	$39.55	$40.89	($0.84)	($0.50)
APS	$30.21	$30.02	$0.16	$0.02	$42.73	$40.87	$1.61	$0.25
ATSI	$30.42	$29.89	$0.09	$0.44	$40.80	$39.82	$0.55	$0.43
BGE	$33.40	$30.34	$2.13	$0.93	$49.72	$41.71	$6.68	$1.33
ComEd	$28.20	$29.85	($0.81)	($0.84)	$28.48	$39.60	($9.15)	($1.97)
DAY	$30.17	$29.96	($0.21)	$0.42	$40.39	$40.58	($0.83)	$0.64
DEOK	$29.29	$30.01	($0.11)	($0.62)	$42.98	$40.50	$3.20	($0.72)
DLCO	$29.84	$29.95	$0.08	($0.19)	$40.90	$40.08	$0.82	($0.00)
Dominion	$32.19	$30.33	$1.45	$0.41	$49.61	$42.45	$6.45	$0.70
DPL	$30.89	$30.33	$0.19	$0.37	$46.11	$42.49	$2.07	$1.55
EKPC	$29.19	$30.36	($0.34)	($0.83)	$37.37	$43.52	($4.75)	($1.40)
JCPL	$29.74	$30.18	($0.65)	$0.21	$40.47	$40.62	($0.75)	$0.60
Met-Ed	$29.90	$29.98	($0.16)	$0.08	$40.04	$40.48	($0.64)	$0.21
PECO	$28.66	$29.99	($1.27)	($0.07)	$40.26	$40.65	($0.72)	$0.33
PENELEC	$29.36	$29.85	($0.59)	$0.09	$39.93	$40.62	($0.89)	$0.20
Pepco	$32.33	$30.17	$1.52	$0.63	$48.47	$41.67	$5.76	$1.04
PPL	$29.14	$29.96	($0.72)	($0.10)	$39.57	$40.83	($1.19)	($0.07)
PSEG	$29.94	$30.05	($0.35)	$0.24	$41.27	$40.40	$0.16	$0.71
RECO	$30.10	$30.13	($0.30)	$0.26	$40.51	$40.26	($0.37)	$0.63
PJM	$30.02	$30.02	$0.02	($0.02)	$40.96	$40.86	$0.11	($0.01)

Hub Components

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

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

	2017 (Jan - Jun)				2018 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.31	$28.69	($0.27)	($1.11)	$34.55	$38.76	($2.55)	($1.66)
AEP-DAY Hub	$28.22	$28.69	$0.00	($0.47)	$36.12	$38.76	($1.85)	($0.79)
ATSI Gen Hub	$28.69	$28.69	($0.03)	$0.02	$39.11	$38.76	$0.76	($0.41)
Chicago Gen Hub	$25.97	$28.69	($1.21)	($1.52)	$27.39	$38.76	($8.65)	($2.72)
Chicago Hub	$26.78	$28.69	($0.81)	($1.11)	$27.96	$38.76	($8.60)	($2.19)
Dominion Hub	$29.73	$28.69	$0.88	$0.16	$44.52	$38.76	$5.45	$0.31
Eastern Hub	$29.48	$28.69	$0.13	$0.66	$39.76	$38.76	($0.62)	$1.62
N Illinois Hub	$26.56	$28.69	($0.87)	($1.26)	$27.75	$38.76	($8.62)	($2.39)
New Jersey Hub	$28.26	$28.69	($0.74)	$0.31	$37.47	$38.76	($2.10)	$0.81
Ohio Hub	$28.32	$28.69	$0.05	($0.42)	$35.70	$38.76	($2.22)	($0.83)
West Interface Hub	$28.97	$28.69	$0.45	($0.17)	$41.99	$38.76	$3.65	($0.42)
Western Hub	$28.76	$28.69	($0.01)	$0.08	$40.52	$38.76	$1.57	$0.19

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

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

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

	2017 (Jan - Jun)				2018 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.76	$29.04	($0.23)	($1.04)	$34.00	$37.83	($2.40)	($1.42)
AEP-DAY Hub	$28.62	$29.04	$0.02	($0.43)	$35.55	$37.83	($1.67)	($0.61)
ATSI Gen Hub	$28.98	$29.04	($0.08)	$0.02	$37.25	$37.83	($0.35)	($0.22)
Chicago Gen Hub	$26.45	$29.04	($1.41)	($1.18)	$26.66	$37.83	($8.86)	($2.31)
Chicago Hub	$27.36	$29.04	($0.92)	($0.75)	$27.23	$37.83	($8.82)	($1.77)
Dominion Hub	$30.25	$29.04	$1.02	$0.19	$43.42	$37.83	$5.20	$0.39
Eastern Hub	$29.73	$29.04	$0.32	$0.37	$39.56	$37.83	$0.58	$1.16
N Illinois Hub	$27.09	$29.04	($1.00)	($0.95)	$26.99	$37.83	($8.83)	($2.00)
New Jersey Hub	$28.53	$29.04	($0.68)	$0.17	$37.61	$37.83	($0.70)	$0.48
Ohio Hub	$28.67	$29.04	$0.02	($0.38)	$35.23	$37.83	($1.95)	($0.64)
West Interface Hub	$29.45	$29.04	$0.59	($0.17)	$40.37	$37.83	$2.83	($0.29)
Western Hub	$29.07	$29.04	$0.18	($0.14)	$39.36	$37.83	$1.44	$0.10

Component Costs

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

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

	Component Costs (Millions)					
(Jan - Jun)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2008	($610)	$1,271	$1,166	$1,827	$16,549	11.0%
2009	($344)	$705	$408	$769	$13,457	5.7%
2010	($373)	$751	$644	$1,022	$16,314	6.3%
2011	($394)	$701	$570	$878	$18,685	4.7%
2012	($262)	$445	$263	$446	$13,991	3.2%
2013	($333)	$494	$306	$468	$15,571	3.0%
2014	($677)	$1,006	$1,442	$1,771	$31,060	5.7%
2015	($398)	$608	$919	$1,129	$23,390	4.8%
2016	($204)	$306	$479	$581	$18,290	3.2%
2017	($222)	$321	$286	$384	$18,960	2.0%
2018	($345)	$521	$897	$1,073	$25,780	4.2%

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

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[14] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point to point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[15]

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

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. Total

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

15 OA Schedule 1 §3.7.

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

The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[16]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR Holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR Holders as it is a measure of the value of transmission in bringing lower cost generation into the area. This logic is not the correct way to account for the congestion payments by load in an area, which are the total difference between energy payments paid by load in that area and energy revenue received by generators serving that load, regardless of whether they are in the same area.

Total congestion costs in PJM in the first six months of 2018 were $896.6 million, which were comprised of load congestion payments of $226.4 million, generation credits of -$699.2 million and explicit congestion of -$29.1 million.

Total Congestion

Table 11-9 shows total congestion for January through June, 2008 through 2018. Total congestion costs in Table 11-9 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[17 18]

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

	Congestion Costs (Millions)			
(Jan - Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166	NA	$16,549	7.0%
2009	$408	(65.0%)	$13,457	3.0%
2010	$644	57.8%	$16,314	3.9%
2011	$570	(11.5%)	$18,685	3.1%
2012	$263	(53.8%)	$13,991	1.9%
2013	$306	16.3%	$15,571	2.0%
2014	$1,442	371.3%	$31,060	4.6%
2015	$919	(36.3%)	$23,390	3.9%
2016	$479	(47.8%)	$18,290	2.6%
2017	$286	(40.4%)	$18,960	1.5%
2018	$897	214.0%	$25,780	3.5%

Table 11-10 shows total congestion by day-ahead and balancing component for the January through June period, by year. Table 11-11 and Table 11-12 show that the increase in balancing explicit costs was the result of an increase in balancing explicit congestion caused by up to congestion (UTCs) which went from $3.5 million in the first six months of 2017 to $18.8 million in the first six months of 2018. The market results were affected by modelling

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

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

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

differences between the day-ahead and real-time market models and large CLMP differences resulting from high gas prices from January 5, 2018 through January 8, 2018, and from the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

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

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$0.0	$1,166.1
2009	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$0.0	$408.2
2010	$151.5	($544.1)	$38.1	$733.8	($7.3)	$18.6	($63.9)	($89.8)	($0.0)	$644.0
2011	$256.0	($420.3)	$25.6	$701.9	$31.1	$56.0	($107.0)	($131.9)	$0.0	$570.0
2012	$56.8	($267.4)	$65.4	$389.6	($5.0)	$19.5	($101.8)	($126.4)	$0.0	$263.3
2013	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	($0.0)	$306.0
2014	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3
2015	$428.5	($655.2)	$9.5	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6
2016	$201.9	($293.4)	$18.7	$514.0	$0.4	$11.5	($23.7)	($34.8)	$0.0	$479.1
2017	$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$0.0	$285.5
2018	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$0.0	$896.6

Table 11-11 and Table 11-12 show the total congestion costs for each transaction type in the first six months of 2018 and 2017. Table 11-11 shows that in the first six months of 2018 DECs paid $12.2 million in congestion costs in the day-ahead market, were paid $16.2 million in congestion credits in the balancing energy market, and were paid $3.9 million in total congestion credits. In the first six months of 2018, INCs paid $16.3 million in congestion charges in the day-ahead market, were paid $24.1 million in congestion credits in the balancing energy market and received $7.8 million in total congestion credits. In the first six months of 2018, up to congestion (UTCs) were paid $40.1 million in congestion credits in the day-ahead market, paid $18.8 million in congestion charges in the balancing market and were paid $21.3 million in total congestion credits.

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June, 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	$12.2	$0.0	$0.0	$12.2	($16.2)	$0.0	$0.0	($16.2)	$0.0	($3.9)
Demand	$32.9	$0.0	$0.0	$32.9	$38.3	$0.0	$0.0	$38.3	$0.0	$71.1
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$0.8	$0.8	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.2
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($39.1)	$0.0	($0.8)	($40.0)	($9.8)	$0.0	($3.7)	($13.5)	$0.0	($53.4)
Generation	$0.0	($928.8)	$0.0	$928.8	$0.0	$58.9	$0.0	($58.9)	$0.0	$869.9
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	($6.1)	$0.0	$6.1	$0.0	($39.7)	($3.0)	$36.7	$0.0	$42.8
INC	$0.0	($16.3)	$0.0	$16.3	$0.0	$24.1	$0.0	($24.1)	$0.0	($7.8)
Internal Bilateral	$205.8	$206.2	$0.4	($0.0)	$3.1	$3.1	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($40.1)	($40.1)	$0.0	$0.0	$18.8	$18.8	$0.0	($21.3)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.6)	($0.4)	$0.2	$0.0	$0.2
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.0	$0.0	($0.6)	$0.0	($0.6)
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$0.0	$896.6

Table 11-12 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June, 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	($6.2)	$0.0	$0.0	($6.2)	($1.0)	$0.0	$0.0	($1.0)	$0.0	($7.2)
Demand	$14.9	$0.0	$0.0	$14.9	$10.6	$0.0	$0.0	$10.6	$0.0	$25.5
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.0	$1.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$1.0
Export	($15.0)	$0.0	($0.2)	($15.3)	($2.7)	$0.0	$1.8	($0.9)	$0.0	($16.1)
Generation	$0.0	($299.3)	$0.0	$299.3	$0.0	$18.3	$0.0	($18.3)	$0.0	$280.9
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	$0.2	$0.0	($0.2)	$0.0	($1.6)	($0.7)	$1.0	$0.0	$0.8
INC	$0.0	($0.3)	$0.0	$0.3	$0.0	$5.6	$0.0	($5.6)	$0.0	($5.3)
Internal Bilateral	$53.5	$53.5	($0.0)	($0.0)	($0.8)	($0.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$2.9	$2.9	$0.0	$0.0	$3.5	$3.5	$0.0	$6.4
Wheel In	$0.0	($0.1)	$0.1	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.2
Wheel Out	($0.1)	$0.0	$0.0	($0.1)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.1)
Total	$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$0.0	$285.5

Table 11-13 shows the change in total congestion cost incurred by transaction type from the first six months of 2017 to the first six months of 2018. Total congestion cost incurred by generation increased by $588.9 million, and total congestion cost incurred by demand increased by $45.6 million.

The total congestion payments to up to congestion transactions (UTCs) increased by $27.7 million, from -$6.4 million in the first six months of 2017 to $21.3 million in the first six months of 2018. In other words, UTCs paid $6.4 million in congestion charges in the first six months of 2017 and were paid $21.3 million in congestion credits in the first six months of 2018. Total day-ahead congestion costs payments to UTCs increased by $43.0 million from -$2.9 million in the first six months of 2017 to $40.1 million in the first six months of 2018. In other words, UTCs paid $2.9 million in congestion charges in the first six months of 2017 and were paid $40.1 million in congestion credits in the first six months of 2018 in the day-ahead market. Over the same period balancing congestion costs paid by UTCs increased by $15.3 million, from $3.5 million in the first six months of 2017 to $18.8 million in the first six months of 2018.

Table 11-13 Change in total PJM congestion costs by transaction type by market: January through June, 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	$18.4	$0.0	$0.0	$18.4	($15.1)	$0.0	$0.0	($15.1)	$0.0	$3.3
Demand	$17.9	$0.0	$0.0	$17.9	$27.7	$0.0	$0.0	$27.7	$0.0	$45.6
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.6)	($0.6)	$0.0	($0.8)
Explicit Congestion and Loss Only	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0
Export	($24.1)	$0.0	($0.6)	($24.7)	($7.2)	$0.0	($5.4)	($12.6)	$0.0	($37.3)
Generation	$0.0	($629.5)	$0.0	$629.5	$0.0	$40.6	$0.0	($40.6)	$0.0	$588.9
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.5	$0.5	$0.0	($0.0)
Import	$0.0	($6.3)	$0.0	$6.3	$0.0	($38.0)	($2.3)	$35.7	$0.0	$42.0
INC	$0.0	($16.0)	$0.0	$16.0	$0.0	$18.5	$0.0	($18.5)	$0.0	($2.4)
Internal Bilateral	$152.3	$152.7	$0.4	$0.0	$3.6	$3.6	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($43.0)	($43.0)	$0.0	$0.0	$15.3	$15.3	$0.0	($27.7)
Wheel In	$0.0	$0.1	($0.1)	($0.2)	$0.0	($0.6)	($0.4)	$0.2	$0.0	$0.1
Wheel Out	$0.1	$0.0	$0.0	$0.1	($0.6)	$0.0	$0.0	($0.6)	$0.0	($0.5)
Total	$164.7	($499.1)	($44.1)	$619.7	$8.4	$24.1	$7.1	($8.6)	$0.0	$611.1

Monthly Congestion

Table 11-14 shows that monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018.

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

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

Table 11-14 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				
Aug	$34.3	($4.2)	$0.0	$30.1				
Sep	$99.7	($1.2)	$0.0	$98.5				
Oct	$50.8	$11.3	$0.0	$62.1				
Nov	$59.9	($1.5)	($0.0)	$58.3				
Dec	$139.8	($18.1)	($0.0)	$121.7				
Total	$733.1	($35.5)	$0.0	$697.6	$916.5	($19.9)	$0.0	$896.6

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

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

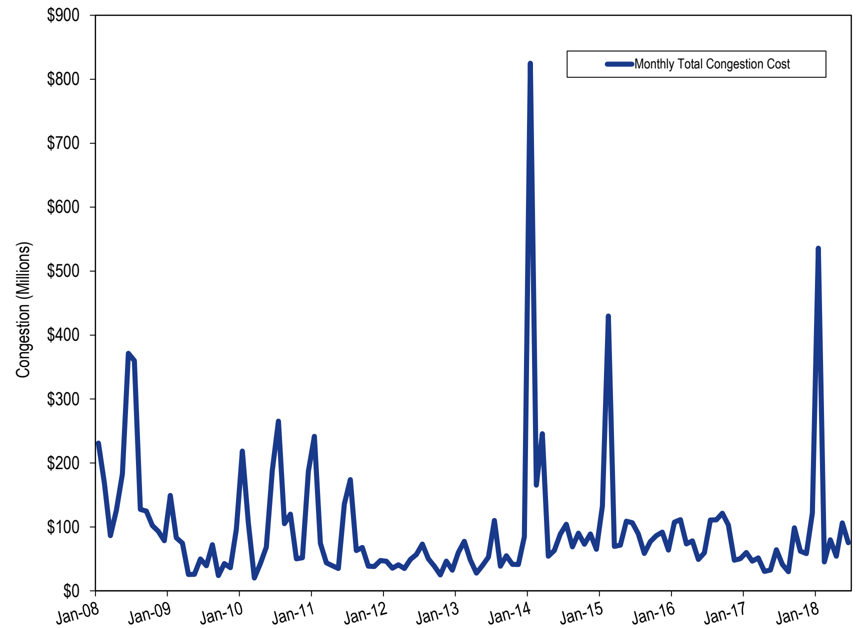


Table 11-15 shows monthly total congestion costs for each virtual transaction type in the first six months of 2018 and Table 11-16 shows the monthly total congestion costs for each virtual transaction type in 2017. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-15 and Table 11-16 show that virtuals were paid in 2017 and the first six months of 2018.

Table 11-15 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through June, 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
Total	$12.2	($16.2)	($3.9)	$16.3	($24.1)	($7.8)	($40.1)	$18.8	($21.3)	($33.0)

Table 11-16 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2017

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

Congested Facilities

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

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first six months of 2018, there were 81,555 day-ahead, congestion event hours compared to 153,062 day-ahead congestion event hours in the first six months of 2017. Of 2018 day-ahead congestion event hours, only 5,830 (7.1 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2018, there were 12,728 real-time, congestion event hours compared to 11,437 real-time, congestion event hours in the first six months of 2017. Of 2018 real-time congestion event hours, 5,888 (46.3 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $343.5 million, or 38.3 percent, of the total PJM congestion costs in the first six months of 2018. The top five constraints were the AEP – DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the Tanners Creek – Miami Fort Flowgate, and the 5004/5005 Interface.

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

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

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

Congestion by Facility Type and Voltage

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

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

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

Balancing congestion costs increased on all types of facilities except lines in the first six months of 2018 compared to the first six months of 2017. Table 11-17 provides congestion event hour subtotals and congestion cost subtotals comparing the first six months of 2018 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[20] [21]

Table 11-18 presents this information for the first six months of 2017.

19 162 FERC ¶ 61,139.

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

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

Table 11-17 Congestion summary (By facility type): January through June, 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	($39.6)	($245.6)	($37.6)	$168.4	($0.5)	$4.7	$6.2	$1.0	$169.4	12,558	3,304
Interface	$60.1	($161.4)	($13.7)	$207.8	$14.7	$23.1	$10.8	$2.4	$210.2	1,951	371
Line	$126.5	($245.8)	$8.8	$381.1	($3.0)	$18.3	($4.8)	($26.1)	$355.0	43,837	7,638
Other	$12.7	($4.2)	$1.0	$17.9	$3.0	($1.7)	($4.7)	($0.0)	$17.9	2,996	406
Transformer	$52.1	($87.9)	$1.1	$141.0	($0.6)	$0.7	$3.6	$2.4	$143.4	20,213	1,009
Unclassified	$0.1	($0.1)	$0.1	$0.3	$1.1	$0.7	$0.0	$0.5	$0.8	NA	NA
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	81,555	12,728

Table 11-18 Congestion summary (By facility type): January through June, 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	($36.9)	($118.8)	($10.9)	$71.0	$5.8	$8.0	$2.5	$0.4	$71.4	14,678	3,613
Interface	$14.3	($10.5)	($1.5)	$23.3	($0.2)	$1.7	$0.3	($1.6)	$21.8	2,765	293
Line	$54.6	($95.5)	$10.3	$160.5	($1.6)	$11.9	$2.3	($11.1)	$149.4	78,470	5,417
Other	$4.1	($1.5)	$0.4	$6.0	$0.2	$0.4	$0.7	$0.5	$6.5	8,846	429
Transformer	$11.0	($19.6)	$5.3	$35.9	$2.1	($0.4)	($0.9)	$1.5	$37.4	48,303	1,685
Unclassified	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	($0.7)	($1.0)	($1.0)	NA	NA
Total	$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$285.5	153,062	11,437

Table 11-19 and Table 11-20 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-19. In the first six months of 2018, there were 81,555 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 5,830 (7.1 percent) were also constrained in the Real-Time Energy Market. There were 37,334 congestion event hours in the Day-Ahead Energy Market for the period February 22, 2018 through June 30, 2018. Of those day-ahead congestion event hours, only 4,113 (11.0 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2017, of the 153,062 day-ahead congestion event hours, only 5,108 (3.3 percent) were binding in the Real-Time Energy Market.[22]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-20. In the first six months of 2018, of the 12,728 congestion event hours in the Real-Time Energy Market, 5,888 (46.3 percent) were also constrained in the Day-Ahead Energy Market. In the first six months of 2017, of the 11,437 real-time congestion event hours, 5,057 (44.2 percent) were also in the Day-Ahead Energy Market.

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

Table 11-19 Congestion event hours (day-ahead against real-time): January through June, 2017 and 2018

	Congestion Event Hours					
	2017 (Jan - Jun)			2018 (Jan - Jun)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	14,678	1,549	10.6%	12,558	1,410	11.2%
Interface	2,765	183	6.6%	1,951	238	12.2%
Line	78,470	2,849	3.6%	43,837	3,969	9.1%
Other	8,846	27	0.3%	2,996	30	1.0%
Transformer	48,303	500	1.0%	20,213	183	0.9%
Total	153,062	5,108	3.3%	81,555	5,830	7.1%

Table 11-20 Congestion event hours (real-time against day-ahead): January through June, 2017 and 2018

	Congestion Event Hours					
	2017 (Jan - Jun)			2018 (Jan - Jun)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	3,613	1,543	42.7%	3,304	1,410	42.7%
Interface	293	216	73.7%	371	262	70.6%
Line	5,417	2,785	51.4%	7,638	4,002	52.4%
Other	429	27	6.3%	406	30	7.4%
Transformer	1,685	486	28.8%	1,009	184	18.2%
Total	11,437	5,057	44.2%	12,728	5,888	46.3%

Table 11-21 shows congestion costs by facility voltage class for the first six months of 2018. Congestion costs in the first six months of 2018 increased for all facilities compared to the first six months of 2017, caused by large increase in day-ahead congestion costs in January, 2018 (Table 11-22).

Table 11-21 Congestion summary (By facility voltage): January through June, 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.3)	$0.1	$2.1	$0.7	$0.3	$0.1	$0.5	$2.5	94	21
500	$65.3	($168.7)	($13.3)	$220.7	$14.0	$20.2	$11.6	$5.5	$226.1	2,714	554
345	$23.3	($191.0)	($5.2)	$209.1	($1.0)	($3.5)	($2.3)	$0.2	$209.3	14,998	1,539
230	$127.4	($26.1)	$2.9	$156.4	$0.2	$5.7	$0.2	($5.4)	$151.0	14,217	3,641
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$0.9	($4.2)	($0.3)	$4.8	$0.2	($0.4)	$0.4	$1.0	$5.8	215	49
138	($16.0)	($310.3)	($22.8)	$271.5	($0.1)	$19.7	$2.1	($17.7)	$253.9	31,255	5,346
115	$1.6	($40.7)	($3.7)	$38.6	$0.1	$3.8	($0.2)	($4.0)	$34.6	8,413	1,217
69	$8.6	($2.1)	$1.5	$12.1	($0.4)	($0.6)	($0.7)	($0.5)	$11.6	7,013	358
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	1,768	3
18	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	309	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
13	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	160	0
12	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	301	0
Unclassified	$0.1	($0.1)	$0.1	$0.3	$1.1	$0.7	$0.0	$0.5	$0.8	NA	NA
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	81,555	12,728

Table 11-22 Congestion summary (By facility voltage): January through June, 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.5	($0.8)	$0.6	$1.9	($0.2)	$0.0	$0.0	($0.2)	$1.7	784	34
500	$19.8	($12.2)	($0.5)	$31.5	$0.1	$2.0	$1.2	($0.7)	$30.8	4,010	440
345	($7.0)	($42.8)	$2.5	$38.3	$4.6	$2.7	($2.8)	($0.9)	$37.3	28,024	1,973
230	$46.7	($23.3)	$0.6	$70.5	$1.0	$5.3	$0.5	($3.8)	$66.7	25,631	2,646
161	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	8	14
138	($13.1)	($146.8)	$0.2	$134.0	$2.7	$13.4	$2.9	($7.8)	$126.2	68,674	4,882
115	($1.6)	($19.5)	$0.4	$18.3	$0.3	$2.0	$2.7	$1.0	$19.3	16,279	995
69	$1.6	($0.4)	($0.2)	$1.8	($2.2)	($4.0)	$0.4	$2.2	$4.0	6,403	453
34	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	2,407	0
18	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	811	0
13	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	31	0
Unclassified	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	($0.7)	($1.0)	($1.0)	NA	NA
Total	$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$285.5	153,062	11,437

Constraint Duration

Table 11-23 lists the constraints for January through June, 2017 and 2018 that were most frequently binding and Table 11-24 shows the constraints which experienced the largest change in congestion event hours from the first six months of 2017 to the first six months of 2018. In Table 11-23, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first six months of 2018. In Table 11-24, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first six months of 2017 to the first six months of 2018.

Table 11-23 Top 25 constraints with frequent occurrence: January through June, 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Graceton - Safe Harbor	Line	1,244	2,889	1,645	459	1,757	1,298	14%	33%	19%	5%	20%	15%
2	Gardners - Texas East	Line	713	1,829	1,116	8	292	284	8%	21%	13%	0%	3%	3%
3	Quad Cities	Transformer	4,326	2,026	(2,300)	0	0	0	49%	23%	(26%)	0%	0%	0%
4	Easton - Emuni	Line	919	1,874	955	1	2	1	10%	21%	11%	0%	0%	0%
5	Lakeview - Greenfield	Line	1,152	1,303	151	121	324	203	13%	15%	2%	1%	4%	2%
6	Brokaw - Leroy	Flowgate	738	1,232	494	289	261	(28)	8%	14%	6%	3%	3%	(0%)
7	Olive	Other	3,665	1,327	(2,338)	0	0	0	42%	15%	(27%)	0%	0%	0%
8	Cedar Grove Sub - Roseland	Line	0	1,198	1,198	3	54	51	0%	14%	14%	0%	1%	1%
9	Newton	Flowgate	147	858	711	50	367	317	2%	10%	8%	1%	4%	4%
10	Flint Lake - Luchtman Road	Flowgate	0	865	865	0	354	354	0%	10%	10%	0%	4%	4%
11	Zion	Line	1,993	1,193	(800)	0	0	0	23%	14%	(9%)	0%	0%	0%
12	Pleasant Prairie - Zion	Flowgate	671	1,011	340	171	60	(111)	8%	12%	4%	2%	1%	(1%)
13	Tanners Creek - Miami Fort	Flowgate	0	958	958	0	0	0	0%	11%	11%	0%	0%	0%
14	Person - Sedge Hill	Line	58	814	756	25	136	111	1%	9%	9%	0%	2%	1%
15	Canton - South Troy	Line	0	949	949	0	0	0	0%	11%	11%	0%	0%	0%
16	Monroe - Lallendorf	Flowgate	37	945	908	0	0	0	0%	11%	10%	0%	0%	0%
17	Emilie - Falls	Line	3,052	751	(2,301)	585	149	(436)	35%	9%	(26%)	7%	2%	(5%)
18	Hinchmans	Transformer	2,529	773	(1,756)	0	0	0	29%	9%	(20%)	0%	0%	0%
19	Roxana - Praxair	Flowgate	534	497	(37)	159	263	104	6%	6%	(0%)	2%	3%	1%
20	Tanners Creek - Miami Fort	Line	325	509	184	12	247	235	4%	6%	2%	0%	3%	3%
21	AEP - DOM	Interface	419	604	185	17	151	134	5%	7%	2%	0%	2%	2%
22	Burnham - Munster	Flowgate	381	751	370	0	0	0	4%	9%	4%	0%	0%	0%
23	Halifax - Roanoke Rapids	Line	0	741	741	0	0	0	0%	8%	8%	0%	0%	0%
24	Braidwood	Transformer	1,220	728	(492)	0	0	0	14%	8%	(6%)	0%	0%	0%
25	Cloverdale	Transformer	137	615	478	13	99	86	2%	7%	5%	0%	1%	1%

Table 11-24 Top 25 constraints with largest year to year change in occurrence: January through June, 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)			(Jan - Jun)		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Westwood	Flowgate	2,880	0	(2,880)	198	0	(198)	33%	0%	(33%)	2%	0%	(2%)
2	Graceton - Safe Harbor	Line	1,244	2,889	1,645	459	1,757	1,298	14%	33%	19%	5%	20%	15%
3	Emilie - Falls	Line	3,052	751	(2,301)	585	149	(436)	35%	9%	(26%)	7%	2%	(5%)
4	Olive	Other	3,665	1,327	(2,338)	0	0	0	42%	15%	(27%)	0%	0%	0%
5	Quad Cities	Transformer	4,326	2,026	(2,300)	0	0	0	49%	23%	(26%)	0%	0%	0%
6	Waukegan	Transformer	2,612	545	(2,067)	0	0	0	30%	6%	(24%)	0%	0%	0%
7	Loretto - Vienna	Line	2,520	577	(1,943)	7	1	(6)	29%	7%	(22%)	0%	0%	(0%)
8	Howard - Shelby	Line	1,937	0	(1,937)	0	0	0	22%	0%	(22%)	0%	0%	0%
9	Hinchmans	Transformer	2,529	773	(1,756)	0	0	0	29%	9%	(20%)	0%	0%	0%
10	Cherry Valley	Transformer	1,910	277	(1,633)	92	0	(92)	22%	3%	(19%)	1%	0%	(1%)
11	Saddlebrook	Transformer	1,982	322	(1,660)	0	0	0	23%	4%	(19%)	0%	0%	0%
12	logtown - North Delphos	Line	1,693	128	(1,565)	0	0	0	19%	1%	(18%)	0%	0%	0%
13	Elwood	Other	1,485	0	(1,485)	0	0	0	17%	0%	(17%)	0%	0%	0%
14	Gould Street - Westport	Line	1,834	417	(1,417)	0	3	3	21%	5%	(16%)	0%	0%	0%
15	Gardners - Texas East	Line	713	1,829	1,116	8	292	284	8%	21%	13%	0%	3%	3%
16	Kendall Co. Energy Ctr.	Transformer	1,697	341	(1,356)	0	0	0	19%	4%	(15%)	0%	0%	0%
17	Cedar Grove Sub - Roseland	Line	0	1,198	1,198	3	54	51	0%	14%	14%	0%	1%	1%
18	East Bend	Transformer	1,701	453	(1,248)	0	0	0	19%	5%	(14%)	0%	0%	0%
19	Maywood	Transformer	1,445	207	(1,238)	0	0	0	16%	2%	(14%)	0%	0%	0%
20	West Moulton - City Of St. Marys	Line	1,629	399	(1,230)	0	0	0	19%	5%	(14%)	0%	0%	0%
21	Powerton	Transformer	1,279	54	(1,225)	0	0	0	15%	1%	(14%)	0%	0%	0%
22	Flint Lake - Luchtman Road	Flowgate	0	865	865	0	354	354	0%	10%	10%	0%	4%	4%
23	West Chicago	Transformer	1,815	606	(1,209)	0	0	0	21%	7%	(14%)	0%	0%	0%
24	Shadelnd - Lafaysouth	Flowgate	662	48	(614)	565	9	(556)	8%	1%	(7%)	6%	0%	(6%)
25	Linden - North Ave	Line	1,113	14	(1,099)	29	0	(29)	13%	0%	(13%)	0%	0%	(0%)

Constraint Costs

Table 11-25 and Table 11-26 show the top constraints affecting congestion costs by facility for the first six months of 2018 and 2017. The AEP – DOM Interface was the largest contributor to congestion costs in the first six months of 2018, with $118.3 million in total congestion costs and 13.2 percent of the total PJM congestion costs in the first six months of 2018.

Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2018

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2018 (Jan - Jun)
1	AEP - DOM	Interface	500	$54.5	($66.2)	($5.1)	$115.6	$13.0	$19.1	$8.8	$2.7	$118.3	13.2%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.7)	$0.5	$3.7	$1.5	$87.6	9.8%
3	Graceton - Safe Harbor	Line	BGE	$86.9	$29.1	$2.3	$60.1	$0.3	$4.5	($1.5)	($5.7)	$54.4	6.1%
4	Tanners Creek - Miami Fort	Flowgate	MISO	($13.7)	($64.7)	($3.5)	$47.5	$0.0	$0.0	$0.0	$0.0	$47.5	5.3%
5	5004/5005 Interface	Interface	500	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	4.0%
6	Batesville - Hubble	Flowgate	MISO	($10.4)	($43.6)	($9.4)	$23.8	($0.5)	($2.1)	$0.4	$2.0	$25.8	2.9%
7	Lakeview - Greenfield	Line	ATSI	($19.5)	($55.4)	($1.6)	$34.3	($1.5)	$8.8	$0.5	($9.8)	$24.5	2.7%
8	Bedington - Black Oak	Interface	500	$9.3	($13.5)	($1.4)	$21.4	$0.6	$0.7	$0.5	$0.5	$21.8	2.4%
9	Capitol Hill - Chemical	Line	AEP	$11.9	($5.0)	$0.5	$17.4	$0.8	($0.8)	($0.1)	$1.5	$18.9	2.1%
10	AP South	Interface	500	$11.2	($7.9)	($1.4)	$17.7	$0.0	$0.1	($0.0)	($0.1)	$17.6	2.0%
11	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.3)	($1.0)	($1.0)	($0.4)	$15.9	1.8%
12	Gardners - Texas East	Line	Met-Ed	($5.7)	($20.1)	($0.1)	$14.3	$0.3	($0.1)	$0.4	$0.8	$15.1	1.7%
13	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.6%
14	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.4	1.5%
15	Nottingham	Other	PECO	$12.3	$0.3	$0.3	$12.3	$0.0	$0.0	$0.0	$0.0	$12.3	1.4%
16	Tanners Creek - Miami Fort	Line	AEP	($2.2)	($10.0)	($0.4)	$7.4	($0.8)	($1.8)	$2.8	$3.9	$11.3	1.3%
17	Monroe - Lallendorf	Flowgate	MISO	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	1.1%
18	Maple - Jackson	Line	ATSI	($8.0)	($17.6)	$1.2	$10.8	$0.2	$0.5	($0.9)	($1.2)	$9.5	1.1%
19	Conastone - Northwest	Line	BGE	$8.0	($1.0)	($0.7)	$8.3	($0.9)	($0.3)	$1.4	$0.8	$9.1	1.0%
20	Flint Lake - Luchtman Road	Flowgate	MISO	$0.2	($10.4)	($4.9)	$5.7	($0.2)	($1.4)	$1.8	$3.0	$8.7	1.0%
21	Conastone - Peach Bottom	Line	500	$7.9	$0.3	$0.1	$7.8	$0.2	$0.1	($0.3)	($0.2)	$7.6	0.9%
22	Olive	Flowgate	MISO	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	0.8%
23	Cedar Grove Sub - Roseland	Line	PSEG	($1.2)	($7.3)	$0.7	$6.8	($0.1)	$0.3	$0.4	($0.0)	$6.8	0.8%
24	Emilie - Falls	Line	PECO	$1.5	($4.4)	$0.1	$6.0	$0.3	$0.4	$0.4	$0.4	$6.4	0.7%
25	Pleasant View - Ashburn	Line	Dominion	$5.3	($1.4)	($0.4)	$6.3	$0.0	$0.0	$0.0	$0.0	$6.3	0.7%

Table 11-26 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2017

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2017 (Jan - Jun)
1	Westwood	Flowgate	MISO	($20.4)	($36.5)	$0.4	$16.5	$1.2	$0.8	($0.5)	($0.1)	$16.4	5.8%
2	Emilie - Falls	Line	PECO	$7.0	($7.7)	$0.1	$14.8	$0.0	$1.4	$0.6	($0.8)	$14.0	4.9%
3	Cherry Valley	Transformer	ComEd	$4.3	($7.1)	$1.2	$12.6	($0.2)	$0.8	$0.3	($0.7)	$11.9	4.2%
4	AP South	Interface	500	$8.4	($4.2)	($1.0)	$11.6	($0.0)	$1.3	$0.8	($0.5)	$11.0	3.9%
5	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	3.8%
6	Conastone - Northwest	Line	BGE	$9.8	($0.7)	($0.4)	$10.1	$0.2	$0.5	$0.9	$0.5	$10.7	3.7%
7	Lake George - Aetna	Flowgate	MISO	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.8	$2.7	$9.2	3.2%
8	Braidwood - East Frankfort	Line	ComEd	($0.3)	($9.0)	$0.0	$8.7	$0.0	$0.1	$0.2	$0.1	$8.8	3.1%
9	Lakeview - Greenfield	Line	ATSI	($1.3)	($8.7)	$0.3	$7.7	($0.3)	$0.3	$0.1	($0.5)	$7.2	2.5%
10	Graceton - Safe Harbor	Line	BGE	$8.0	$1.3	$0.2	$6.9	$0.4	$0.6	$0.5	$0.3	$7.2	2.5%
11	Conastone - Peach Bottom	Line	500	$6.1	$0.3	$0.4	$6.2	$0.2	$0.0	($0.0)	$0.1	$6.3	2.2%
12	Greentown	Flowgate	MISO	($1.4)	($7.6)	($0.7)	$5.6	($0.8)	($0.2)	$1.1	$0.5	$6.1	2.1%
13	Bedington - Black Oak	Interface	500	$3.5	($2.3)	($0.0)	$5.7	$0.0	$0.2	$0.4	$0.2	$5.9	2.1%
14	Byron - Cherry Valley	Flowgate	MISO	($0.7)	($5.4)	($0.1)	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1.6%
15	Pleasant View - Ashburn	Line	Dominion	$4.0	($2.9)	($0.2)	$6.7	($1.1)	$1.0	($0.1)	($2.2)	$4.5	1.6%
16	Middletown Jct - Brunner Island	Line	PPL	$1.8	($2.4)	($0.2)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	1.4%
17	Bagley - Graceton	Line	BGE	$3.2	($0.5)	($0.0)	$3.7	$0.0	$0.1	$0.1	$0.1	$3.7	1.3%
18	Nottingham	Other	PECO	$4.4	$0.9	$0.1	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	1.2%
19	Loretto - Vienna	Line	DPL	$3.6	$0.9	$0.7	$3.4	$0.0	($0.0)	($0.0)	($0.0)	$3.4	1.2%
20	Brokaw - Leroy	Flowgate	MISO	$0.5	($3.4)	($1.8)	$2.1	($0.1)	$0.7	$1.9	$1.1	$3.2	1.1%
21	Shadelnd - Lafaysouth	Flowgate	MISO	($3.4)	($5.6)	$0.1	$2.2	$5.8	$3.7	($1.2)	$0.9	$3.1	1.1%
22	Capitol Hill - Chemical	Line	AEP	$1.7	($0.7)	$0.5	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	1.0%
23	Crozet - Dooms	Line	Dominion	$2.4	($0.1)	$0.1	$2.6	$0.2	$0.4	$0.1	($0.0)	$2.6	0.9%
24	Nelson	Flowgate	MISO	($1.8)	($4.3)	($0.0)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	0.9%
25	Quad Cities	Transformer	ComEd	($0.8)	($2.9)	$0.5	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	0.9%

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first six months of 2018. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted average CLMP in the first six months of 2018. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in the first six months of 2018.

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

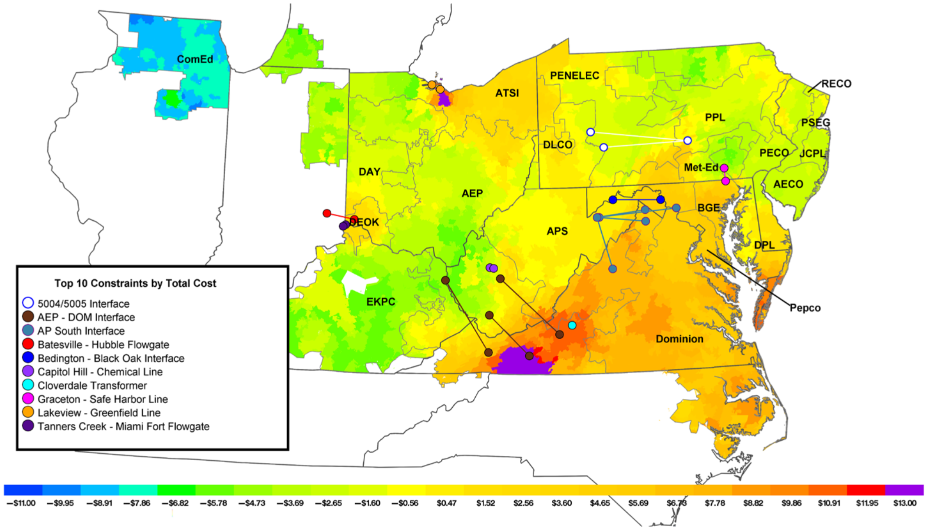


Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: January through June, 2018

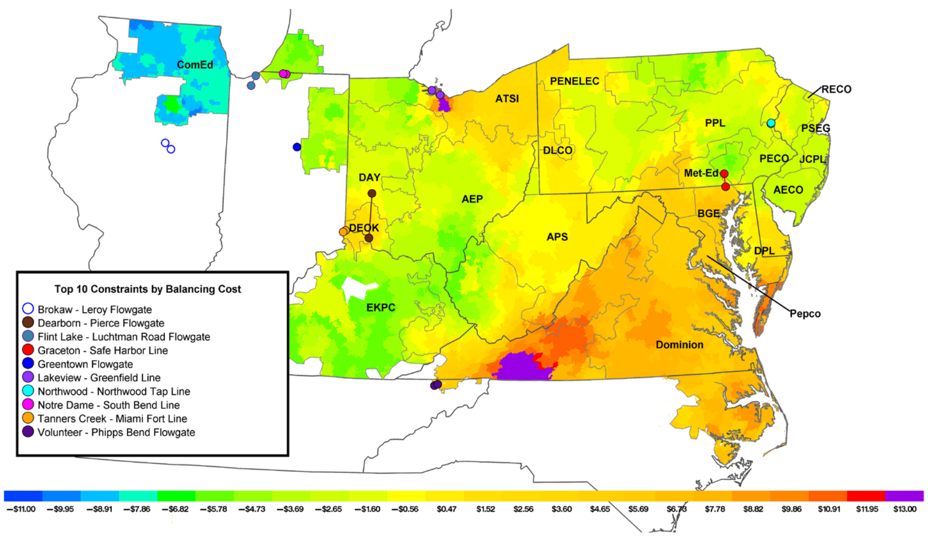
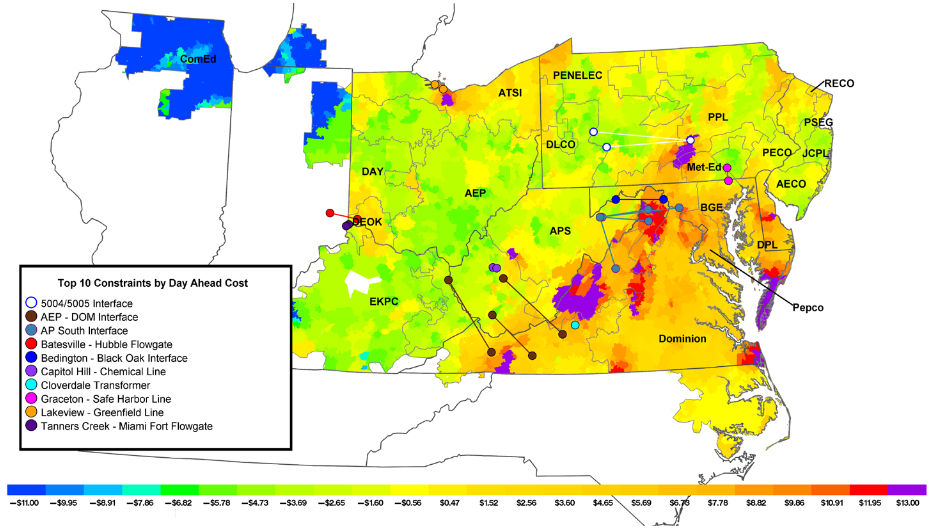


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: January through June, 2018



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

As of June 30, 2018, PJM had 137 flowgates eligible for M2M (Market to Market) coordination and MISO had 269 flowgates eligible for M2M coordination.

Table 11-27 and Table 11-28 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first six months of 2018 and 2017, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first six months of 2018, the Tanners Creek – Miami Fort Flowgate made the most significant contribution to positive congestion while the Greentown Flowgate contributed to most negative congestion.

23 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>.
24 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 11-27 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June, 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	($13.7)	($64.7)	($3.5)	$47.5	$0.0	$0.0	$0.0	$0.0	$47.5	958	0
2	Batesville - Hubble	($10.4)	($43.6)	($9.4)	$23.8	($0.5)	($2.1)	$0.4	$2.0	$25.8	197	111
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	$13.4	1,232	261
5	Monroe - Lallendorf	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	945	0
6	Flint Lake - Luchtman Road	$0.2	($10.4)	($4.9)	$5.7	($0.2)	($1.4)	$1.8	$3.0	$8.7	865	354
7	Olive	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	445	0
8	Pierce - Beckjord	($2.0)	($8.4)	($0.2)	$6.2	$0.0	$0.0	$0.0	$0.0	$6.2	218	0
9	Volunteer - Phipps Bend	($0.3)	($2.9)	($0.7)	$1.9	($1.0)	($3.1)	$1.2	$3.3	$5.3	7	28
10	Burnham - Munster	$0.6	($4.0)	($0.1)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	751	0
11	Plymouth - Leesburg	($1.9)	($7.7)	($2.0)	$3.7	($0.5)	$0.4	$1.5	$0.6	$4.4	306	163
12	Greentown	($0.0)	($0.7)	($0.2)	$0.5	($0.9)	$6.0	$2.1	($4.8)	($4.3)	121	72
13	Northwest Tap - Purdue	($2.0)	($6.3)	($1.1)	$3.2	$1.1	$2.1	$1.3	$0.2	$3.5	111	85
14	Eugene - Cayuga	($0.4)	($4.4)	($0.6)	$3.4	$0.0	$0.0	($0.0)	($0.0)	$3.4	293	23
15	Quad Cities - Cordova	($1.9)	($4.0)	$1.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	541	0
16	Roxana - Praxair	$0.2	($3.7)	($3.3)	$0.7	$1.1	$0.8	($3.2)	($2.8)	($2.2)	497	263
17	Maroa - E GooseCreek	($0.0)	($2.0)	($0.5)	$1.5	$0.0	($0.1)	$0.3	$0.5	$2.0	189	54
18	Morocco - Allen Junction	($0.4)	($4.0)	($1.7)	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	23	0
19	Reynolds - Magnetation	($0.0)	($1.7)	$0.1	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	77	8
20	Newton	($0.5)	($2.3)	$0.1	$1.9	$0.2	$0.1	($0.2)	($0.2)	$1.7	858	367

Table 11-28 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June, 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	($20.4)	($36.5)	$0.4	$16.5	$1.2	$0.8	($0.5)	($0.1)	$16.4	2,880	198
2	Alpine - Belvidere	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	339	0
3	Lake George - Aetna	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.8	$2.7	$9.2	483	244
4	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.8)	($0.2)	$1.1	$0.5	$6.1	425	248
5	Byron - Cherry Valley	($0.7)	($5.4)	($0.1)	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	175	0
6	Brokaw - Leroy	$0.5	($3.4)	($1.8)	$2.1	($0.1)	$0.7	$1.9	$1.1	$3.2	738	289
7	Shadelnd - Lafaysouth	($3.4)	($5.6)	$0.1	$2.2	$5.8	$3.7	($1.2)	$0.9	$3.1	662	565
8	Nelson	($1.8)	($4.3)	($0.0)	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	421	0
9	Havana E - Havana S	($1.6)	($4.2)	($0.2)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	938	0
10	Olive - Bosserman	$1.2	($1.5)	($0.4)	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	127	0
11	Reynolds - Magnetation	($0.2)	($1.3)	$0.3	$1.4	$0.0	($0.0)	($0.1)	($0.0)	$1.4	256	19
12	Eugene - Cayuga	($0.4)	($1.8)	($0.1)	$1.2	$0.2	$0.0	($0.2)	($0.0)	$1.2	262	74
13	Burnham - Munster	$0.0	($0.9)	$0.2	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	381	0
14	Pleasant Prairie - Zion	($0.3)	($1.7)	($0.1)	$1.3	$0.0	$0.0	($0.2)	($0.2)	$1.1	671	171
15	Monroe - Lallendorf	($0.3)	($1.7)	($0.4)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	37	0
16	Dune Acres - Michigan City	($0.1)	($0.8)	($0.7)	($0.0)	($0.1)	($0.0)	($0.9)	($0.9)	($0.9)	83	39
17	Babcock - Stillwell	($0.6)	($1.6)	($0.6)	$0.4	($0.2)	($0.2)	$0.3	$0.4	$0.8	264	105
18	Havana E - Havana	$0.0	$0.0	$0.0	$0.0	$0.2	$0.7	($0.3)	($0.7)	($0.7)	0	352
19	Kewanee - Hennepin	($0.7)	($1.8)	($0.3)	$0.9	($0.1)	$0.0	($0.1)	($0.2)	$0.7	242	47
20	Batesville - Hubble	$0.0	$0.0	$0.0	$0.0	$0.2	$0.3	($0.6)	($0.7)	($0.7)	0	9

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.[25] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[26]

In the first six months of 2018, none of the NYISO flowgates were binding and only one flowgate was binding in the first six months of 2017. Table 11-29 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first six months of 2017.

25 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>.

26 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 11-29 Congestion cost impact from NYISO flowgates affecting PJM dispatch (By facility): January through June, 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

Congestion Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-30 and Table 11-31 show the 500 kV constraints affecting congestion costs in PJM for the first six months of 2018 and 2017. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-30 Regional constraints summary (By facility): January through June, 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	$54.5	($66.2)	($5.1)	$115.6	$13.0	$19.1	$8.8	$2.7	$118.3	604	151
2	5004/5005 Interface	Interface	($15.4)	($54.3)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	174	47
3	Bedington - Black Oak	Interface	$9.3	($13.5)	($1.4)	$21.4	$0.6	$0.7	$0.5	$0.5	$21.8	289	51
4	AP South	Interface	$11.2	($7.9)	($1.4)	$17.7	$0.0	$0.1	($0.0)	($0.1)	$17.6	351	13
5	Conastone - Peach Bottom	Line	$7.9	$0.3	$0.1	$7.8	$0.2	$0.1	($0.3)	($0.2)	$7.6	352	125
6	CPL - DOM	Interface	$5.9	($1.1)	$0.8	$7.8	$0.2	$1.5	($0.4)	($1.7)	$6.1	250	98
7	West	Interface	($1.4)	($6.1)	($0.8)	$4.0	$0.0	($0.0)	($0.0)	($0.0)	$3.9	66	9
8	East	Interface	($2.2)	($5.6)	($0.1)	$3.3	($0.0)	$0.0	($0.1)	($0.1)	$3.2	101	2
9	Hunterstown	Transformer	($0.0)	($1.9)	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	148	0
10	Central	Interface	($3.2)	($6.2)	($1.3)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	28	0
11	Keeney - Rockspring	Line	($0.8)	($1.9)	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	158	0
12	Breinigsville - Wescosville	Line	$0.0	($0.2)	$0.4	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	108	0
13	Limerick	Transformer	($0.1)	($0.5)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	41	0
14	502 Junction	Transformer	($0.0)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3	0
15	Three Mile Island	Transformer	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
16	Yukon	Transformer	$0.0	$0.0	$0.0	$0.0	$0.1	($0.0)	($0.2)	$0.0	$0.0	0	7
17	Wylie Ridge	Transformer	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	1
18	Hope Creek - Red Lion	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
19	Cabot - Keystone	Line	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2

Table 11-31 Regional constraints summary (By facility): January through June, 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	AP South	Interface	$8.4	($4.2)	($1.0)	$11.6	($0.0)	$1.3	$0.8	($0.5)	$11.0	723	63
2	Conastone - Peach Bottom	Line	$6.1	$0.3	$0.4	$6.2	$0.2	$0.0	($0.0)	$0.1	$6.3	1,158	198
3	Bedington - Black Oak	Interface	$3.5	($2.3)	($0.0)	$5.7	$0.0	$0.2	$0.4	$0.2	$5.9	771	55
4	AEP - DOM	Interface	$1.2	($1.4)	$0.2	$2.8	($0.0)	$0.1	($0.3)	($0.4)	$2.4	419	17
5	West	Interface	($0.3)	($1.7)	($0.1)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	152	0
6	Three Mile Island	Transformer	$0.8	($0.3)	$0.1	$1.2	($0.0)	($0.1)	$0.1	$0.1	$1.3	269	17
7	5004/5005 Interface	Interface	($0.4)	($1.5)	($0.2)	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	59	1
8	Conastone	Transformer	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	33	2
9	Cabot - Keystone	Line	($0.1)	($0.5)	$0.1	$0.5	$0.1	$0.2	($0.0)	($0.2)	$0.3	96	18
10	Belmont	Transformer	($0.0)	($0.2)	($0.1)	$0.1	$0.0	$0.1	($0.3)	($0.4)	($0.3)	42	52
11	East	Interface	($0.2)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	82	0
12	Bristers - Ox	Line	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
13	Cabot	Other	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
14	Juniata	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	34	0
15	502 Junction	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
16	Cunningham - Elmont	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
17	Valley - Bath County	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
18	Redlion	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
19	Keystone - South Bend	Line	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	1
20	Black Oak	Transformer	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. Physical entities are further categorized into physical ARR holders if the entity is eligible for ARRs and physical non ARR holders if the entity is not eligible for ARRs.

Financial entities received $2.7 million in net congestion credits in the first six months of 2018 and received $2.8 million in net congestion credits in the first six months of 2017 (Table 11-33). Physical ARR holder entities paid $581.4 million in congestion charges in the first six months of 2018 and $178.6 million in congestion charges in the first six months of 2017. Physical non ARR holder paid $317.8 million in congestion charges in the first six months of 2018 and $109.8 million in congestion charges in the first six months of 2017.

Explicit congestion costs are the primary source of congestion credits to financial entities, primarily UTCs. In the first six months of 2018, the total explicit congestion cost was -$29.1 million, of which -$21.3 million (73.2 percent) was contributed by UTCs. In the first six months of 2017, the total explicit congestion cost was $7.9 million, of which $6.4 million (81.4 percent) was contributed by UTCs.

Table 11-32 Congestion cost by type of participant: January through June, 2018

		Congestion Costs (Millions)									
		Day-Ahead				Balancing					
Participant Type		Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial		$31.4	($3.7)	($46.1)	($11.0)	($15.5)	$5.1	$29.0	$8.3	$0.0	($2.7)
Physical	ARR Holder	$29.1	($544.8)	($2.5)	$571.4	$26.9	$15.0	($1.9)	$10.0	$0.0	$581.4
	Non ARR Holder	$151.3	($196.5)	$8.3	$356.1	$3.3	$25.7	($15.9)	($38.3)	$0.0	$317.8
Total		$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$0.0	$896.6

Table 11-33 Congestion cost by type of participant: January through June, 2017

		Congestion Costs (Millions)									
		Day-Ahead				Balancing					
Participant Type		Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial		($5.9)	$0.2	($2.4)	($8.4)	($0.4)	$2.4	$8.5	$5.6	$0.0	($2.8)
Physical	ARR Holder	$16.6	($160.9)	$0.4	$178.0	$7.4	$5.9	($0.9)	$0.6	$0.0	$178.6
	Non ARR Holder	$36.4	($85.2)	$5.7	$127.3	($0.9)	$13.2	($3.4)	($17.5)	$0.0	$109.8
Total		$47.1	($246.0)	$3.8	$296.8	$6.1	$21.5	$4.1	($11.3)	$0.0	$285.5

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.[27] Figure 11-5 shows that day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined and increased after December 7, 2015, when UTC activity increased. Figure 11-5 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined.

In the first six months of 2018, the average hourly UTC submitted MW decreased by 59.4 percent and UTC cleared MW decreased 48.0 percent, compared to the first six months of 2017. Day-ahead congestion event hours decreased by 46.7 percent from 153,062 congestion event hours in the first six months of 2017 to 81,555 congestion event hours in the first six months of 2018 (Table 11-19). Day-ahead congestion event hours decreased by 63.6 percent from 102,706 congestion event hours for the period February 22, 2017, through June 30, 2017, to 37,334 congestion event hours for the period February 22, 2018 through June 30, 2018.

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

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

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

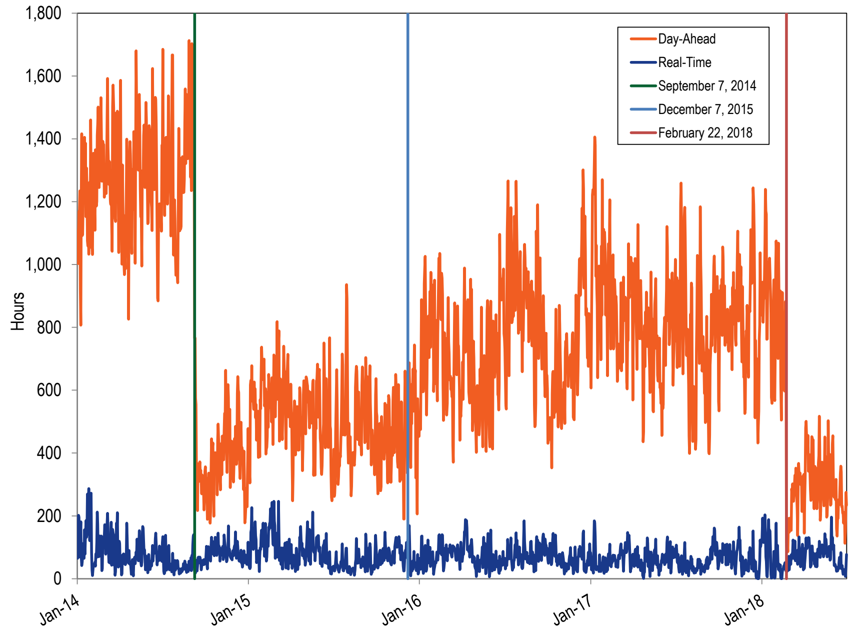


Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: January 2014 through June 2018

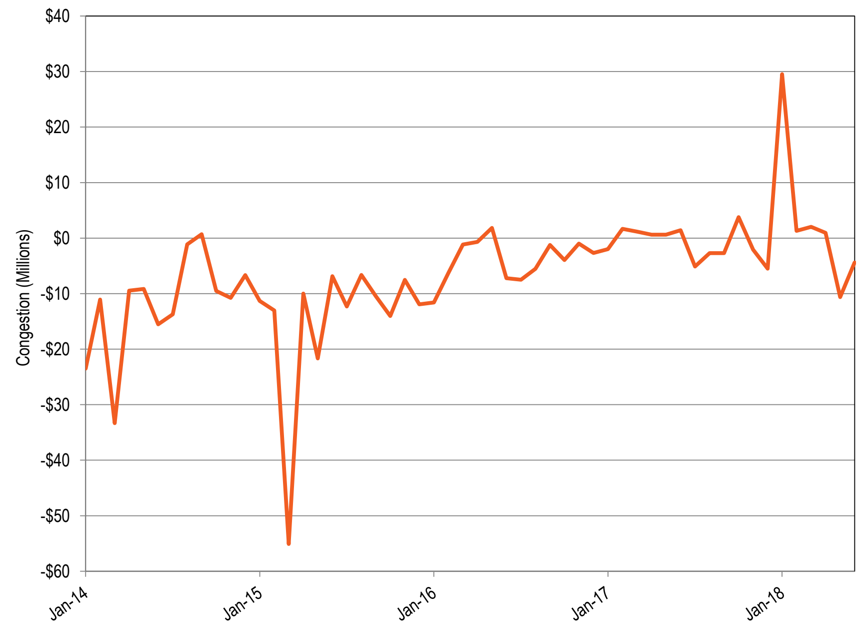


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014 through June 30, 2018. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March of 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January of 2018.

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.[28] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[29] 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.[30]

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.

28 OA Schedule 1 §3.7
29 *Id.*
30 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 80 (June 1, 2008) at 70.

- **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.[31]

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first six months of 2018 was $521.4 million, which was comprised of load loss payments of -$22.9 million, generation loss credits of -$550.2 million, explicit loss costs of -$6.0 million and inadvertent loss charges of $0.0 million (Table 11-35).

Monthly marginal loss costs in the first six months of 2018 ranged from $49.5 million in February to $222.8 million in January. Total marginal loss surplus increased in the first six months of 2018 by $76.8 million or 78.2 percent from $98.2 million in the first six months of 2017 to $175.0 million in the first six months of 2018.

Table 11-34 shows the total marginal loss component costs and the total PJM billing for January through June, 2008 through 2018.

Table 11-34 Total PJM loss component costs (Dollars (Millions)): January through June, 2008 through 2018[32]

(Jan - Jun)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,271	NA	$16,549	7.7%
2009	$705	(44.6%)	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%
2013	$494	11.2%	$15,571	3.2%
2014	$1,006	103.5%	$31,060	3.2%
2015	$608	(39.5%)	$23,390	2.6%
2016	$306	(49.7%)	$18,290	1.7%
2017	$321	4.8%	$18,960	1.7%
2018	$521	62.6%	$25,780	2.0%

Table 11-35 shows PJM total marginal loss costs by accounting category for January through June, 2008 through 2018. Table 11-36 shows PJM total marginal loss costs by accounting category by market for January through June, 2008 through 2018.

31 OA Schedule 1 §3.7.

32 The loss costs include net inadvertent charges.

Table 11-35 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through June, 2008 through 2018

	Marginal Loss Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($130.8)	($1,349.6)	$52.4	$0.0	$1,271.2
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.6)	$0.0	$444.9
2013	$8.6	($512.4)	($26.6)	($0.0)	$494.5
2014	($35.7)	($1,083.3)	($41.4)	$0.0	$1,006.2
2015	($15.4)	($635.5)	($11.9)	$0.0	$608.3
2016	($19.5)	($338.7)	($13.4)	$0.0	$305.8
2017	($24.9)	($363.5)	($17.9)	$0.0	$320.6
2018	($22.9)	($550.2)	($6.0)	$0.0	$521.4

Table 11-36 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through June, 2008 through 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	($64.9)	($1,299.8)	$64.3	$1,299.2	($65.9)	($49.8)	($11.9)	($28.0)	$0.0	$1,271.2
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.5	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.9
2013	($7.2)	($528.2)	$25.0	$546.0	$15.9	$15.8	($51.6)	($51.6)	($0.0)	$494.5
2014	($75.4)	($1,118.8)	$51.6	$1,095.0	$39.7	$35.6	($93.0)	($88.8)	$0.0	$1,006.2
2015	($33.2)	($643.0)	$15.6	$625.4	$17.8	$7.4	($27.5)	($17.1)	$0.0	$608.3
2016	($23.3)	($339.8)	$18.9	$335.4	$3.9	$1.1	($32.4)	($29.5)	$0.0	$305.8
2017	($29.6)	($364.1)	$30.2	$364.7	$4.6	$0.6	($48.1)	($44.0)	$0.0	$320.6
2018	($26.3)	($543.9)	$16.7	$534.4	$3.4	($6.3)	($22.7)	($12.9)	$0.0	$521.4

Table 11-37 and Table 11-38 show the total loss costs for each transaction type in the first six months of 2018 and 2017. In the first six months of 2018, generation paid loss costs of $522.6 million, 100.2 percent of total loss costs. In the first six months of 2017, generation paid loss costs of $342.6 million, 106.8 percent of total loss costs.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In the first six months of 2018, DECs were paid $0.9 million in loss credits in the day-ahead market, paid $0.9 million in congestion costs in the balancing energy market and received $0.0 million in net payment for losses. In the first six months of 2018, INCs paid $7.2 million in loss costs in the day-ahead market, were paid $8.0 million in congestion credits in the balancing energy market and were paid $0.7 million in net payment for losses. In the first six months of 2018, up to congestion paid $17.1 million in loss costs in the day-ahead market, were paid $22.3 million in loss credits in the balancing energy market and received $5.2 million in net payment for losses.

Table 11-37 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through June, 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	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	$0.0	($0.0)
Demand	($3.8)	$0.0	$0.0	($3.8)	$7.0	$0.0	$0.0	$7.0	$0.0	$3.2
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($12.7)	$0.0	($0.0)	($12.7)	($5.1)	$0.0	$0.2	($4.9)	$0.0	($17.6)
Generation	$0.0	($525.9)	$0.0	$525.9	$0.0	$3.4	$0.0	($3.4)	$0.0	$522.6
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Import	$0.0	($2.2)	$0.0	$2.2	$0.0	($18.2)	($0.4)	$17.8	$0.0	$20.0
INC	$0.0	($7.2)	$0.0	$7.2	$0.0	$8.0	$0.0	($8.0)	$0.0	($0.7)
Internal Bilateral	($8.8)	($8.6)	$0.3	($0.0)	$0.5	$0.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$17.1	$17.1	$0.0	$0.0	($22.3)	($22.3)	$0.0	($5.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($26.3)	($543.9)	$16.7	$534.4	$3.4	($6.3)	($22.7)	($12.9)	$0.0	$521.4

Table 11-38 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through June, 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	($5.4)	$0.0	$0.0	($5.4)	$3.9	$0.0	$0.0	$3.9	$0.0	($1.5)
Demand	($2.8)	$0.0	$0.0	($2.8)	$4.8	$0.0	$0.0	$4.8	$0.0	$2.0
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($9.8)	$0.0	$0.1	($9.7)	($5.1)	$0.0	$0.4	($4.7)	$0.0	($14.4)
Generation	$0.0	($342.4)	$0.0	$342.4	$0.0	($0.2)	$0.0	$0.2	$0.0	$342.6
Grandfathered Overuse	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.2)	($0.2)	$0.0	($0.4)
Import	$0.0	($1.2)	$0.0	$1.2	$0.0	($7.8)	($0.1)	$7.6	$0.0	$8.9
INC	$0.0	($8.9)	$0.0	$8.9	$0.0	$7.5	$0.0	($7.5)	$0.0	$1.4
Internal Bilateral	($11.6)	($11.6)	$0.0	($0.0)	$1.1	$1.1	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$29.9	$29.9	$0.0	$0.0	($48.2)	($48.2)	$0.0	($18.3)
Wheel In	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.3
Total	($29.6)	($364.1)	$30.2	$364.7	$4.6	$0.6	($48.1)	($44.0)	$0.0	$320.6

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for January 1, 2017 through June 30, 2018.

Table 11-39 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				
Aug	$64.4	($7.6)	$0.0	$56.8				
Sep	$58.3	($6.2)	$0.0	$52.0				
Oct	$51.8	($4.7)	$0.0	$47.1				
Nov	$55.3	($4.0)	$0.0	$51.3				
Dec	$96.8	($5.3)	$0.0	$91.5				
Total	$769.9	($79.1)	$0.0	$690.8	$534.4	($12.9)	$0.0	$521.4

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

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

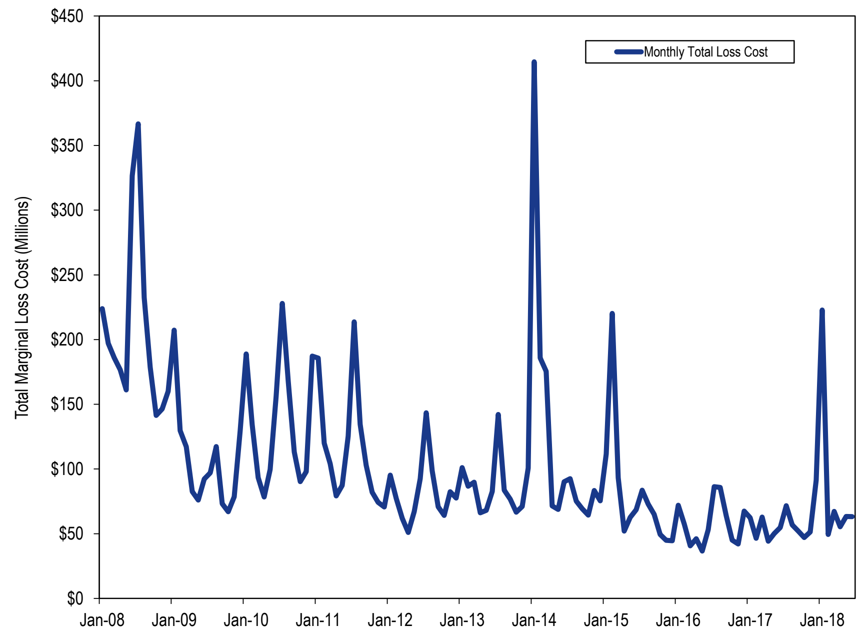


Table 11-40 and Table 11-41 show the monthly total loss costs for each virtual transaction type in the first six months of 2018 and year of 2017.

Table 11-40 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January through June, 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)
Total	($0.9)	$0.9	($0.0)	$7.2	($8.0)	($0.7)	$17.1	($22.3)	($5.2)	($5.9)

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

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

Marginal Loss Costs and Loss Credits

Total loss surplus are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (load energy payments minus generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-42 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through June, 2008 through 2018. The total marginal loss surplus increased $76.8 million in the first six months of 2018 from the first six months of 2017.

Table 11-42 Marginal loss surplus (Dollars (Millions)): January through June, 2008 through 2018[33]

Marginal Loss Surplus (Millions)						
			Net Residual Market Adjustment			
(Jan - Jun)	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($610.2)	$1,271.2	$0.0	$0.0	$0.0	$661.0
2009	($343.6)	$704.8	$0.0	($1.2)	($0.0)	$362.5
2010	($372.8)	$750.9	$0.0	$0.6	($0.0)	$377.5
2011	($393.9)	$701.5	($0.0)	($0.9)	$0.0	$308.4
2012	($262.0)	$444.9	$0.1	$0.8	$0.0	$182.1
2013	($332.6)	$494.5	$0.1	$0.8	($0.0)	$161.3
2014	($677.2)	$1,006.2	$0.0	$3.9	$0.1	$325.0
2015	($397.6)	$608.3	($0.3)	$3.7	($0.1)	$206.7
2016	($204.2)	$305.8	$0.0	$1.3	($0.1)	$100.5
2017	($222.2)	$320.6	$0.0	$0.3	($0.1)	$98.2
2018	($345.2)	$521.4	($0.0)	$1.3	($0.0)	$175.0

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can be more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for the first six months of 2018 was -$345.2 million, which was comprised of load energy payments of $23,072.1 million, generation energy credits of $23,422.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of $4.9 million. The monthly energy costs for the first six months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Table 11-43 shows total energy component costs and total PJM billing, for January through June, 2008 through 2018. The total energy component costs are net energy costs.

Table 11-43 Total PJM energy component costs (Dollars (Millions)): January through June, 2008 through 2018[34]

(Jan - Jun)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($610)	NA	$16,549	(3.7%)
2009	($344)	(43.7%)	$13,457	(2.6%)
2010	($373)	8.5%	$16,314	(2.3%)
2011	($394)	5.7%	$18,685	(2.1%)
2012	($262)	(33.5%)	$13,991	(1.9%)
2013	($333)	26.9%	$15,571	(2.1%)
2014	($677)	103.6%	$31,060	(2.2%)
2015	($398)	(41.3%)	$23,390	(1.7%)
2016	($204)	(48.6%)	$18,290	(1.1%)
2017	($222)	8.8%	$18,960	(1.2%)
2018	($345)	55.3%	$25,780	(1.3%)

Energy costs for January through June, 2008 through 2018 are shown in Table 11-44 and Table 11-45. Table 11-44 shows PJM energy costs by accounting category and Table 11-45 shows PJM energy costs by market category.

33 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.

34 The energy costs include net inadvertent charges.

Table 11-44 Total PJM energy costs by accounting category (Dollars (Millions)): January through June, 2008 through 2018

	Energy Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$61,281.2	$61,891.4	$0.0	$0.0	($610.2)
2009	$22,815.7	$23,162.1	$0.0	$2.9	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($393.9)
2012	$16,823.4	$17,092.7	$0.0	$7.2	($262.0)
2013	$20,488.2	$20,819.3	$0.0	($1.5)	($332.6)
2014	$39,885.0	$40,556.7	$0.0	($5.4)	($677.2)
2015	$24,267.0	$24,667.1	$0.0	$2.5	($397.6)
2016	$14,857.8	$15,062.3	$0.0	$0.4	($204.2)
2017	$16,768.7	$16,991.8	$0.0	$0.9	($222.2)
2018	$23,072.1	$23,422.1	$0.0	$4.9	($345.2)

Table 11-45 Total PJM energy costs by market category (Dollars (Millions)): January through June, 2008 through 2018

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$42,539.7	$43,214.3	$0.0	($674.6)	$18,741.5	$18,677.1	$0.0	$64.5	$0.0	($610.2)
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.9	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($393.9)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.6)	($56.2)	$0.0	($27.4)	$7.2	($262.0)
2013	$20,543.4	$20,895.6	$0.0	($352.2)	($55.1)	($76.3)	$0.0	$21.2	($1.5)	($332.6)
2014	$39,831.7	$40,780.0	$0.0	($948.3)	$53.3	($223.3)	$0.0	$276.6	($5.4)	($677.2)
2015	$24,389.1	$24,858.0	$0.0	($468.9)	($122.1)	($190.9)	$0.0	$68.8	$2.5	($397.6)
2016	$14,970.7	$15,252.9	$0.0	($282.3)	($112.9)	($190.6)	$0.0	$77.7	$0.4	($204.2)
2017	$16,974.1	$17,296.6	$0.0	($322.5)	($205.3)	($304.8)	$0.0	$99.4	$0.9	($222.2)
2018	$23,126.4	$23,506.8	$0.0	($380.4)	($54.4)	($84.7)	$0.0	$30.3	$4.9	($345.2)

Table 11-46 and Table 11-47 show the total energy costs for each transaction type in the first six months of 2018 and the first six months of 2017. In the first six months of 2018, generation was paid $16,315.6 million and demand paid $15,914.4 million in net energy payment. In the first six months of 2017, generation was paid $11,567.5 million and demand paid $11,060.5 million in net energy payment.

Table 11-46 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through June, 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	$515.3	$0.0	$0.0	$515.3	($532.4)	$0.0	$0.0	($532.4)	($17.0)
Demand	$15,627.6	$0.0	$0.0	$15,627.6	$286.8	$0.0	$0.0	$286.8	$15,914.4
Demand Response	($0.7)	$0.0	$0.0	($0.7)	$0.7	$0.0	$0.0	$0.7	$0.0
Export	$398.3	$0.0	$0.0	$398.3	$184.6	$0.0	$0.0	$184.6	$583.0
Generation	$0.0	$16,382.6	$0.0	($16,382.6)	$0.0	($67.0)	$0.0	$67.0	($16,315.6)
Import	$0.0	$85.4	$0.0	($85.4)	$0.0	$432.9	$0.0	($432.9)	($518.3)
INC	$0.0	$453.0	$0.0	($453.0)	$0.0	($456.5)	$0.0	$456.5	$3.5
Internal Bilateral	$6,585.8	$6,585.8	$0.0	($0.0)	$5.9	$5.9	$0.0	$0.0	($0.0)
Total	$23,126.4	$23,506.8	$0.0	($380.4)	($54.4)	($84.7)	$0.0	$30.3	($350.0)

Table 11-47 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through June, 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	$632.5	$0.0	$0.0	$632.5	($626.2)	$0.0	$0.0	($626.2)	$6.3
Demand	$11,055.4	$0.0	$0.0	$11,055.4	$5.1	$0.0	$0.0	$5.1	$11,060.5
Demand Response	($0.3)	$0.0	$0.0	($0.3)	$0.2	$0.0	$0.0	$0.2	($0.0)
Export	$360.5	$0.0	$0.0	$360.5	$190.9	$0.0	$0.0	$190.9	$551.3
Generation	$0.0	$11,623.9	$0.0	($11,623.9)	$0.0	($56.4)	$0.0	$56.4	($11,567.5)
Import	$0.0	$46.7	$0.0	($46.7)	$0.0	$218.5	$0.0	($218.5)	($265.3)
INC	$0.0	$699.9	$0.0	($699.9)	$0.0	($691.6)	$0.0	$691.6	($8.3)
Internal Bilateral	$4,926.0	$4,926.0	$0.0	$0.0	$224.7	$224.7	$0.0	($0.0)	$0.0
Total	$16,974.1	$17,296.6	$0.0	($322.5)	($205.3)	($304.8)	$0.0	$99.4	($223.1)

Monthly Energy Costs

Table 11-48 shows a monthly summary of energy costs by market type for January 1, 2017 through June 30, 2018. Marginal total energy costs in the first six months of 2018 decreased from the first six months of 2017. Monthly total energy costs in the first six months of 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Table 11-48 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)				
Aug	($52.7)	$12.8	$1.1	($38.9)				
Sep	($47.9)	$9.0	$1.3	($37.5)				
Oct	($43.7)	$8.2	$1.7	($33.8)				
Nov	($45.4)	$9.7	$0.1	($35.5)				
Dec	($75.1)	$12.4	$0.8	($61.9)				
Total	($648.5)	$166.2	$7.1	($475.2)	($380.4)	$30.3	$4.9	($345.2)

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

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

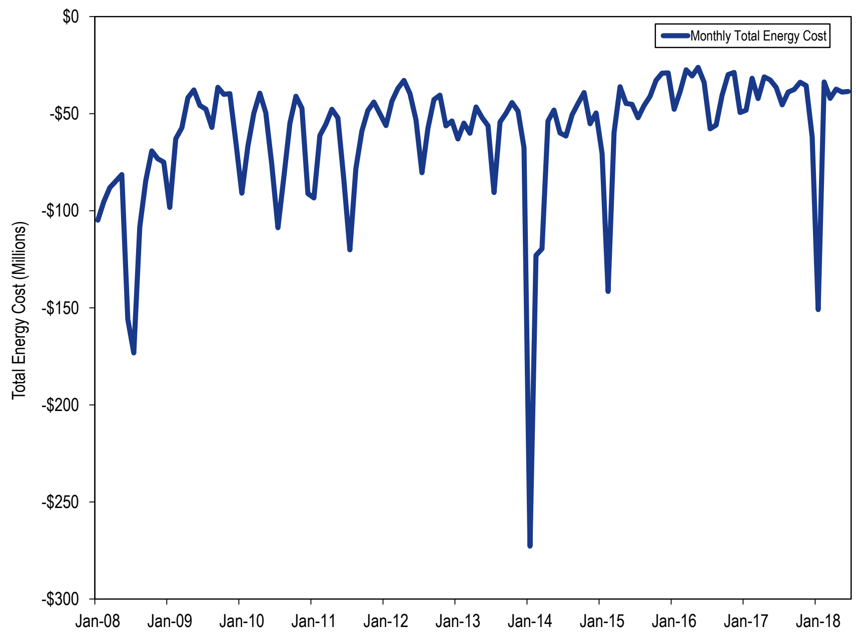


Table 11-49 and Table 11-50 show the monthly total energy costs for each virtual transaction type in 2017 and the first six months of 2018. In the first six months of 2018, DECs paid $515.3 million in energy costs in the day-ahead market, were paid $532.4 million in energy credits in the balancing energy market and were paid $17.0 million in net payment for energy. In the first six months of 2018, INCs were paid $453.0 million in energy credits in the day-ahead market, paid $456.5 million in energy costs in the balancing market and paid $3.5 million in energy costs. In the first six months of 2017, DECs paid $632.5 million in energy costs in the day-ahead market, were paid $626.2 million in energy credits in the balancing energy market and paid $6.3 million in energy costs. In the first six months of 2017, INCs were paid $699.9 million in energy credits in the day-ahead market, paid $691.6 million in energy cost in the balancing energy market and received $8.3 million in net payment for energy.

Table 11-49 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January through June, 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
Total	$515.3	($532.4)	($17.0)	($453.0)	$456.5	$3.5	($13.5)

Table 11-50 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)