Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2]

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

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

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

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

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

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[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 while generators are paid the price at their bus.

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

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by load at the buses within a defined area minus total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of location. Constraint based congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of

1 Withdrawals are generically referred to as load and injections are generically referred to as generation, unless specified otherwise.
2 The difference in losses is not part of congestion.

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 for the first six months of 2019 were calculated as of July 16, 2019, and are subject to change, based on continued PJM billing updates.

generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $642.5 million or 71.7 percent, from $896.6 million in the first six months of 2018 to $254.1 million in the first six months of 2019.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $605.0 million or 66.0 percent, from $916.5 million in the first six months of 2018 to $311.5 million in the first six months of 2019.
- **Balancing Congestion.** Negative balancing congestion costs increased by $37.5 million or 188.6 percent, from -$19.9 million in the first six months of 2018 to -$57.4 million in the first six months of 2019. Balancing explicit costs decreased by $40.9 million or 364.9 percent, from $11.2 million in the first six months of 2018 to -$29.7 million in the first six months of 2019.
- **Real-Time Congestion.** Real-time congestion costs decreased by $749.1 million or 71.8 percent, from $1,042.9 million in the first six months of 2018 to $293.8 million in the first six months of 2019.
- **Monthly Congestion.** Monthly total congestion costs in the first six months of 2019 ranged from $22.2 million in April to $100.2 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 Conastone - Peach Bottom Line, the Siegfried Transformer, the AP South Interface, the East Interface, and the CPL - DOM 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 2019. 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.

  Day-ahead congestion frequency decreased by 36.5 percent from 81,854 congestion event hours in the first six months of 2018 to 51,990 congestion event hours in the first six months of 2019. The majority (94.2 percent) of the decrease occurred in January and February of 2019. The decrease was largely a result of the decrease in cleared up to congestion (UTC) transactions between January and February, 2018 and January and February, 2019.[5]

  Real-time congestion frequency decreased by 35.6 percent from 12,867 congestion event hours in the first six months of 2018 to 8,287 congestion event hours in the first six months of 2019.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.

  The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first six months of 2019. With $40.7 million in total congestion costs, it accounted for 16.0 percent of the total PJM congestion costs in the first six months of 2019.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** CT Price Setting Logic caused -$0.2 million of day-ahead congestion in the first six months of 2019 and -$2.6 million of balancing congestion in the first six months of 2019. None of the closed loop interfaces was binding in the first six months of 2019 or 2018.
- **Zonal Congestion.** AEP had the largest zonal congestion costs among all control zones in the first six months of 2019. AEP had $38.8 million in zonal congestion costs, comprised of $48.0 million in zonal day-ahead congestion costs and -$9.2 million in zonal balancing congestion costs. The Conastone - Peach Bottom Line, the AP South Interface, the East Interface, the Hazard Transformer, and the Conastone - Northwest Line contributed $13.7 million, or 35.2 percent of the AEP zonal congestion costs.

5 162 FERC ¶ 61,139

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $198.3 million or 38.0 percent, from $521.4 million in the first six months of 2018 to $323.1 million in the first six months of 2019. The loss MWh in PJM decreased by 230.1 GWh or 3.0 percent, from 7,657.9 GWh in the first six months of 2018 to 7,427.8 GWh in the first six months of 2019. The loss component of real-time LMP in the first six months of 2019 was $0.02, compared to $0.02 in the first six months of 2018.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2019 ranged from $38.8 million in April to $86.5 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $184.6 million or 34.5 percent, from $534.4 million in the first six months of 2018 to $349.7 million in the first six months of 2019.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $13.7 million or 105.9 percent, from -$12.9 million in the first six months of 2018 to -$26.6 million in the first six months of 2019.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first six months of 2019 by $71.4 million or 40.7 percent, from $175.6 million in the first six months of 2018, to $104.2 million in the first six months of 2019.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $126.2 million or 36.6 percent, from -$345.2 million in the first six months of 2018 to -$218.9 million in the first six months of 2019.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $112.4 million or 29.6 percent, from -$380.4 million in the first six months of 2018 to -$268.0 million in the first six months of 2019.
- **Balancing Energy Costs.** Balancing energy costs increased by $17.4 million or 57.2 percent, from $30.3 million in the first six months of 2018 to $47.7 million in the first six months of 2019.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Conclusion

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

Total congestion in the first six months of 2019 decreased significantly from the first six months of 2018. The decrease was a result of high day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018.

The monthly total congestion costs ranged from $22.2 million in April to $100.2 million in January, 2019.

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

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[6] For the 2017/2018 planning period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion. For the 2018/2019 planning period, following the FERC decision to allocate some of the surplus to load, the offset was 92.1 percent.

Issues

Closed Loop Interfaces and CT Pricing Logic

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

Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource. In the case of a closed loop interface, all buses within the interface are modeled as having a distribution factor (DFAX) of 1.0 to the constraint and therefore have the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affects the CLMP of downstream (constrained side) buses in proportion to their DFAX to that constraint.[7] The objective of making inflexible resources marginal is to minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

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

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

Use of closed loop interfaces and CT price setting logic requires the manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic force higher cost inflexible units to be marginal. Unlike constraints that restrict the use of lower cost output in the system solution, the closed loop interface and CT price setting logic constraints are forcing the use of the relatively high cost resource. The sign of the shadow price of this artificial constraint in the optimization solution, unlike normal security constraints in a least cost dispatch optimization, is therefore positive because relaxing this constraint will cause system costs to go up, not down. Increasing the limit (relaxing) a closed loop interface or CT price setting logic constraint requires an increase in the output from the high cost unit from within the artificially constrained area, and a decrease in output from low price generation from outside the artificially constrained area. This means that increasing the limit of closed loop interface or CT price setting logic constraint causes a net increase in incremental cost for any increase in the flow limit of the constraint and a positive, rather than the usual negative, shadow price for the modeled transmission constraint.

The nature of the closed loop interface or CT price setting logic constraint is that more power is produced than consumed in the artificial closed loop or constrained area than would result without the closed loop. This means that there are more high CLMP generation credits than high CLMP load charges associated within the constrained area within the closed loop interface or CT

6 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.

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

price setting logic constraint. The rest of the system receives power from the closed loop/constrained area, the higher cost generators outside the closed loop/constrained area are backed down and prices are lower outside the loop than they would have been without the closed loop. While all of the generation within the artificially constrained area is paid the higher CLMP in the form of generation credits, a smaller amount of load (in some cases no load) pays this higher CLMP in the form of load charges within the loop. The residual energy is delivered and paid for at a lower CLMP outside the closed loop/constrained area. The result is that PJM pays out more to generators in the closed loop than it collects from load. The result of using closed loops and CT price setting logic is that uneconomic generation costs that would otherwise be collected as uplift are being realized as negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing rather than to deviations as uplift charges.

Balancing Congestion Cost Calculation Logic Change

Effective April 1, 2018, PJM made a significant change to the calculation and allocation of implicit balancing congestion.

Prior to April 1, 2018, implicit balancing congestion costs calculated at the zonal and aggregate level were determined by bus specific deviations between day-ahead and real-time MWh priced at the bus specific congestion price in the Real-Time Energy Market.

As of April 1, 2018, with the introduction of five minute settlements, implicit zonal and aggregate balancing congestion costs are determined by netting the bus specific hourly deviations across every bus in a zone or aggregate and pricing the resulting deviation in zone or aggregate total deviations at the zonal or aggregate congestion price in the Real Time Energy Market. As a result of the introduction of netting hourly deviations across every bus in a zone or aggregate, the allocation of implicit balancing congestion was reduced for MW deviations associated with load and virtual bids that settle at zones and aggregates.

The netting of zonal and aggregate deviations decreased the allocation of negative balancing charges to load deviations and increased the allocation to real-time load plus real-time exports.

Table 11-1 shows the total implicit balancing congestion costs that would have resulted from applying either the pre or post April 1, 2018 settlement rules for the first six months of 2017, 2018 and 2019. Table 11-1 also shows the actual total implicit balancing congestion costs for the first six months of 2017, 2018 and 2019 based on the methods in place at the time.[8] The only difference is that the actual implicit balancing congestion in 2018 reflects the fact that in the first quarter of 2018 the implicit balancing congestion cost was calculated under the pre April 1, 2018, settlement rule and in the second quarter of 2018, the implicit balancing congestion cost was calculated under the post April 1, 2018 settlement rule. Table 11-1 shows that the post April 1, 2018, settlement rule, if applied to the first six months of 2017, 2018 and 2019, would have caused negative balancing congestion costs to increase relative to the pre April 1, 2018, settlement rule. Table 11-1 shows that the post April 1, 2018, settlement rule caused negative total implicit balancing costs to increase by $3.60 million (14.9 percent) in the first six months of 2019, and would have caused such costs to increase by $1.4 million (9.1 percent) in the first six months of 2017 and to increase by $11.3 million (38.9 percent) in the first six months of 2018.

8 In 2017, the actual total balancing congestion costs were calculated using old method. In 2018, the actual total balancing congestion costs were calculated using the old method in the first quarter and using the new method in the second quarter. In 2019, the actual total balancing congestion costs were calculated using the new method.

Table 11-1 Total balancing implicit congestion cost ($M) (old method and new method): January through June, 2017 through 2019

	Balancing ($ Milllion)								
	Old Method			New Method			Actual		
(Jan - Jun)	Load Payments	Generation Credits	Total Implicit	Load Payments	Generation Credits	Total Implicit	Load Payments	Generation Credits	Total Implicit
2017	$6.1	$21.5	($15.4)	$5.0	$21.8	($16.8)	$6.1	$21.5	($15.4)
2018	$17.2	$46.1	($28.9)	$3.3	$43.5	($40.2)	$14.7	$45.8	($31.1)
2019	$5.2	$29.3	($24.1)	$0.2	$28.0	($27.7)	$0.2	$28.0	($27.7)

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 of LMP is a load-weighted system price. No congestion or losses are included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (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.[9] The first derivative of total losses with respect to the power flow is 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.[10] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy by withdrawals in the transmission constrained area and the total revenue received by injections to meet the withdrawals in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-2 shows the PJM real-time, load-weighted average LMP components for January through June, 2008 through 2019.[11]

The load-weighted average real-time LMP decreased $14.95 or 35.2 percent from $42.44 in the first six months of 2018 to $27.49 in the first six months of 2019. The load-weighted, average real-time congestion component decreased by $0.02 from $0.04 in the first six months of 2018 to $0.02 in the first six months of 2019. The load-weighted average real-time loss component in the first six months of 2019 was $0.02 compared to $0.02 in the first six months of 2018. The load-weighted, average real-time energy component decreased

9 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>.

10 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.

11 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 average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

by $14.92 or 35.2 percent from $42.37 in the first six months of 2018 to $27.45 in the first six months of 2019.

Table 11-2 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2008 through 2019[12]

(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
2019	$27.49	$27.45	$0.02	$0.02

Table 11-3 shows the PJM day-ahead, load-weighted average LMP components for January through June, 2008 through 2019.[13] The load-weighted average day-ahead LMP decreased $12.99, or 31.7 percent, from $40.96 in the first six months of 2018 to $27.97 in the first six months of 2019. The load-weighted, average congestion component decreased $0.05 from $0.11 in the first six months of 2018 to $0.06 in the first six months of 2019. The load-weighted, average loss component was -$0.01 in the first six months of 2018 and -$0.01 in the first six months of 2019. The load-weighted average energy component decreased $12.94, or 31.7 percent, from $40.86 in the first six months of 2018 to $27.92 in the first six months of 2019.

Table 11-3 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2008 through 2019

(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)
2019	$27.97	$27.92	$0.06	($0.01)

Table 11-4 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours.

Table 11-4 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2018 through June 2019

	2018		2019	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$96.69	$24.03	$33.75	$21.61
Feb	$27.00	$23.93	$28.99	$23.33
Mar	$33.35	$23.64	$30.81	$24.22
Apr	$35.74	$24.92	$27.04	$24.43
May	$38.78	$17.24	$24.92	$20.27
Jun	$34.55	$21.81	$24.94	$19.28
Jul	$37.08	$26.09		
Aug	$38.64	$25.11		
Sep	$36.83	$26.29		
Oct	$35.27	$26.11		
Nov	$37.64	$26.58		
Dec	$34.60	$24.19		
Avg	$41.15	$24.71	$28.81	$21.79

12 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.

13 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 11-5 for January through June, 2018 and 2019. In the first six months of 2019, BGE had the highest real-time congestion component of all control zones, $1.70, and PPL had the lowest real-time congestion component, -$1.73.

Table 11-5 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$40.49	$41.77	($2.32)	$1.05	$26.96	$27.27	($0.66)	$0.35
AEP	$41.23	$42.27	($0.38)	($0.67)	$27.65	$27.44	$0.39	($0.17)
APS	$44.74	$42.73	$1.69	$0.33	$27.89	$27.58	$0.22	$0.09
ATSI	$43.91	$41.20	$2.36	$0.35	$27.74	$27.29	$0.12	$0.33
BGE	$52.10	$43.65	$6.80	$1.65	$30.33	$27.70	$1.70	$0.93
ComEd	$29.33	$40.90	($9.15)	($2.42)	$24.97	$27.17	($1.15)	($1.05)
DAY	$41.76	$41.92	($0.67)	$0.51	$28.67	$27.48	$0.37	$0.81
DEOK	$43.29	$42.06	$2.40	($1.17)	$27.46	$27.37	$0.35	($0.26)
DLCO	$43.94	$41.46	$2.52	($0.03)	$27.15	$27.22	$0.03	($0.09)
Dominion	$51.20	$44.06	$6.43	$0.71	$28.93	$27.60	$1.03	$0.31
DPL	$47.15	$44.07	$0.78	$2.31	$28.29	$27.81	($0.28)	$0.77
EKPC	$38.69	$44.90	($4.57)	($1.63)	$27.64	$27.99	$0.06	($0.41)
JCPL	$41.37	$42.06	($1.73)	$1.04	$27.04	$27.44	($0.69)	$0.30
Met-Ed	$41.10	$42.22	($1.85)	$0.72	$27.45	$27.55	($0.13)	$0.03
OVEC	NA	NA	NA	NA	$26.31	$27.02	$0.14	($0.85)
PECO	$41.24	$42.37	($1.91)	$0.78	$26.53	$27.44	($0.96)	$0.05
PENELEC	$41.30	$41.48	($0.63)	$0.45	$26.78	$27.38	($0.64)	$0.04
Pepco	$50.27	$43.35	$5.79	$1.13	$29.35	$27.64	$1.08	$0.63
PPL	$40.39	$42.62	($2.67)	$0.44	$25.71	$27.65	($1.73)	($0.21)
PSEG	$40.93	$41.46	($1.54)	$1.01	$27.34	$27.22	($0.09)	$0.21
RECO	$40.42	$41.41	($1.86)	$0.86	$27.11	$27.19	($0.21)	$0.12
PJM	$42.44	$42.37	$0.04	$0.02	$27.49	$27.45	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-6 for January through June, 2018 and 2019. In the first six months of 2019, BGE had the highest day-ahead congestion component of all control zones, $2.28, and PPL had the lowest day-ahead congestion component, -$1.83.

Table 11-6 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$39.91	$40.45	($1.05)	$0.51	$26.98	$27.81	($1.05)	$0.21
AEP	$39.55	$40.89	($0.84)	($0.50)	$28.19	$27.99	$0.35	($0.15)
APS	$42.73	$40.87	$1.61	$0.25	$28.55	$28.05	$0.42	$0.08
ATSI	$40.80	$39.82	$0.55	$0.43	$28.55	$27.78	$0.37	$0.40
BGE	$49.72	$41.71	$6.68	$1.33	$31.18	$28.10	$2.28	$0.80
ComEd	$28.48	$39.60	($9.15)	($1.97)	$25.23	$27.61	($1.46)	($0.92)
DAY	$40.39	$40.58	($0.83)	$0.64	$29.19	$27.93	$0.47	$0.79
DEOK	$42.98	$40.50	$3.20	($0.72)	$28.27	$27.89	$0.58	($0.20)
DLCO	$40.90	$40.08	$0.82	($0.00)	$27.85	$27.69	$0.24	($0.08)
Dominion	$49.61	$42.45	$6.45	$0.70	$30.05	$28.13	$1.68	$0.23
DPL	$46.11	$42.49	$2.07	$1.55	$28.27	$28.30	($0.56)	$0.53
EKPC	$37.37	$43.52	($4.75)	($1.40)	$28.02	$28.56	($0.06)	($0.49)
JCPL	$40.47	$40.62	($0.75)	$0.60	$26.81	$27.90	($1.30)	$0.21
Met-Ed	$40.04	$40.48	($0.64)	$0.21	$27.08	$27.95	($0.76)	($0.11)
OVEC	NA	NA	NA	NA	$29.38	$30.13	$0.12	($0.87)
PECO	$40.26	$40.65	($0.72)	$0.33	$26.28	$27.88	($1.51)	($0.09)
PENELEC	$39.93	$40.62	($0.89)	$0.20	$28.06	$28.21	($0.29)	$0.13
Pepco	$48.47	$41.67	$5.76	$1.04	$30.48	$28.16	$1.73	$0.59
PPL	$39.57	$40.83	($1.19)	($0.07)	$25.85	$28.04	($1.83)	($0.37)
PSEG	$41.27	$40.40	$0.16	$0.71	$27.27	$27.74	($0.63)	$0.15
RECO	$40.51	$40.26	($0.37)	$0.63	$27.86	$27.92	($0.18)	$0.11
PJM	$40.96	$40.86	$0.11	($0.01)	$27.97	$27.92	$0.06	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-7 for January through June, 2018 and 2019.[14]

Table 11-7 Hub real-time, average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.55	$38.76	($2.55)	($1.66)	$25.71	$26.38	$0.16	($0.83)
AEP-DAY Hub	$36.12	$38.76	($1.85)	($0.79)	$26.53	$26.38	$0.37	($0.22)
ATSI Gen Hub	$39.11	$38.76	$0.76	($0.41)	$26.44	$26.38	$0.18	($0.11)
Chicago Gen Hub	$27.39	$38.76	($8.65)	($2.72)	$23.87	$26.38	($1.20)	($1.31)
Chicago Hub	$27.96	$38.76	($8.60)	($2.19)	$24.32	$26.38	($1.12)	($0.94)
Dominion Hub	$44.52	$38.76	$5.45	$0.31	$27.18	$26.38	$0.74	$0.06
Eastern Hub	$39.76	$38.76	($0.62)	$1.62	$26.19	$26.38	($0.76)	$0.58
N Illinois Hub	$27.75	$38.76	($8.62)	($2.39)	$24.14	$26.38	($1.15)	($1.09)
New Jersey Hub	$37.47	$38.76	($2.10)	$0.81	$25.95	$26.38	($0.60)	$0.18
Ohio Hub	$35.70	$38.76	($2.22)	($0.83)	$26.60	$26.38	$0.41	($0.19)
West Interface Hub	$41.99	$38.76	$3.65	($0.42)	$26.54	$26.38	$0.37	($0.21)
Western Hub	$40.52	$38.76	$1.57	$0.19	$26.63	$26.38	$0.26	($0.01)

The day-ahead components of LMP for each hub are presented in Table 11-8 for January through June, 2018 and 2019.

Table 11-8 Hub day-ahead, average LMP components (Dollars per MWh): January through June, 2018 and 2019

	2018 (Jan - Jun)				2019 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.00	$37.83	($2.40)	($1.42)	$26.17	$26.82	$0.14	($0.79)
AEP-DAY Hub	$35.55	$37.83	($1.67)	($0.61)	$27.01	$26.82	$0.37	($0.19)
ATSI Gen Hub	$37.25	$37.83	($0.35)	($0.22)	$27.24	$26.82	$0.42	($0.00)
Chicago Gen Hub	$26.66	$37.83	($8.86)	($2.31)	$24.22	$26.82	($1.41)	($1.19)
Chicago Hub	$27.23	$37.83	($8.82)	($1.77)	$24.62	$26.82	($1.39)	($0.81)
Dominion Hub	$43.42	$37.83	$5.20	$0.39	$28.03	$26.82	$1.23	($0.03)
Eastern Hub	$39.56	$37.83	$0.58	$1.16	$26.31	$26.82	($0.95)	$0.44
N Illinois Hub	$26.99	$37.83	($8.83)	($2.00)	$24.42	$26.82	($1.42)	($0.98)
New Jersey Hub	$37.61	$37.83	($0.70)	$0.48	$25.93	$26.82	($1.00)	$0.12
Ohio Hub	$35.23	$37.83	($1.95)	($0.64)	$27.04	$26.82	$0.38	($0.16)
West Interface Hub	$40.37	$37.83	$2.83	($0.29)	$27.27	$26.82	$0.62	($0.17)
Western Hub	$39.36	$37.83	$1.44	$0.10	$27.43	$26.82	$0.58	$0.02

14 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.

Congestion

Congestion Accounting

Total congestion costs equal implicit congestion costs plus explicit congestion costs. Implicit congestion costs equal congestion payments minus congestion credits. Explicit congestion costs are the net congestion costs associated with point to point energy transactions. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[15] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

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

Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total congestion costs equal congestion payments netted against congestion credits on an hourly basis, by billing organization, and summed for the given period. Congestion payments are made by withdrawals and congestion credits are paid to injections. Withdrawals are generically referred to as load and injections are generically referred to as generation.

Congestion payments and 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

15 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.

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.[16]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. Total congestion costs, when positive, measure the total congestion payment by a participant group and when negative, measure the total congestion credit paid to a participant group. Load congestion payments, when positive, measure the total congestion payment by load and when negative, measure the total congestion credit paid by load. Generation congestion credits, when negative, measure the total congestion payment by generation and when positive, measure the total congestion credit paid to generation. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The accounting definitions can be misleading. Load pays for congestion. Generation does not pay for congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying for congestion.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[17]

Load weighted LMP components are calculated relative to a load weighted average LMP. At the load weighted reference bus, which represents the load center of the system, the LMP includes no congestion or loss components, by definition. The average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related congestion charges is logically zero and the small differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. The marginal generator is the highest cost generator required to meet the load subject to constraints. This means that the average generation weighted CLMP for generation resources is lower than the LMP at the load weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation

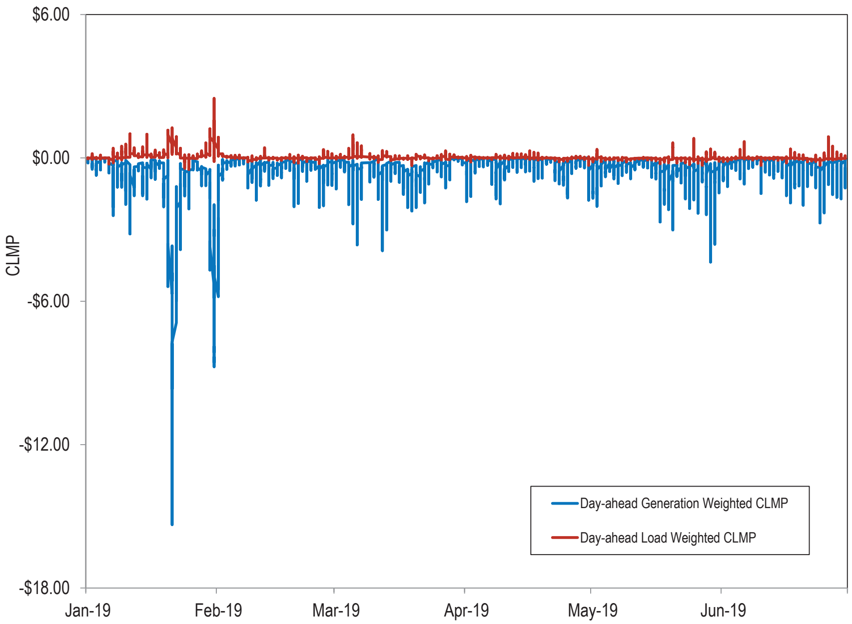
16 PJM Operating Agreement Schedule 1 §3.7.

17 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>.

bus CLMPs is negative. This means that total generation congestion credits are negative. Total congestion is the difference between the load charges and the negative generation credits.

Figure 11-1 shows the CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in the first six months of 2019, day-ahead generation weighted CLMPs were generally negative and day-ahead load weighted CLMPs were generally equal to or slightly greater than zero. Figure 11-1 also shows that in the first six months of 2019, load paid more for energy as a result of transmission constraints than generation was paid to provide that energy.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load weighted CLMPs: January through June, 2019



Total Congestion

Total congestion costs in PJM in the first six months of 2019 were $254.1 million, which were comprised of load congestion payments of $100.6 million, generation credits of -$160.3 million and explicit congestion of -$6.8 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy.

Table 11-9 shows total congestion for January through June, 2008 through 2019. 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.[18 19]

Table 11-9 Total PJM congestion component costs (Dollars (Millions)): January through June, 2008 through 2019

	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%
2019	$254	(71.7%)	$20,070	1.3%

Congestion charges and credits are not in and of themselves congestion. Congestion charges and credits are adjustments to energy charges and credits reflecting marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of congestion credits and charges at the close

18 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>.
19 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>.

of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-10 shows total congestion by day-ahead and balancing component for January through June, 2008 through 2019. Table 11-11 and Table 11-12 show that the decrease in balancing explicit costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in the first six months of 2019 from the first six months of 2018. The market results were affected by large CLMP differences resulting from high gas prices from January 5, 2018, through January 8, 2018. Table 11-10 shows that the balancing explicit costs incurred by UTCs were $29.5 million in January of 2018.

Table 11-10 Total PJM congestion credits and charges by accounting category by market (Dollars (Millions)): January through June, 2008 through 2019

	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
2019	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$0.0	$254.1

Table 11-11 and Table 11-12 show the total congestion charges and credits for each transaction type in the first six months of 2019 and 2018. Table 11-11 shows that in the first six months of 2019 DECs paid $6.7 million in congestion charges in the day-ahead market, were paid $7.5 million in congestion credits in the balancing energy market, resulting in a net payment of $0.8 million in total congestion credits. In the first six months of 2019, INCs paid $8.3 million in congestion charges in the day-ahead market, were paid $12.7 million in congestion credits in the balancing energy market resulting in a net payment of $4.4 million in total congestion credits. In the first six months of 2019, up to congestion (UTCs) paid $22.7 million in congestion charges in the day-ahead market, were paid $29.9 million in congestion credits in the balancing market resulting in a total payment of $7.2 million in total congestion credits.

Table 11-11 Total PJM congestion credits and charges by transaction type by market (Dollars (Millions)): January through June, 2019

	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	$6.7	$0.0	$0.0	$6.7	($7.5)	$0.0	$0.0	($7.5)	$0.0	($0.8)
Demand	$18.2	$0.0	$0.0	$18.2	$8.1	$0.0	$0.0	$8.1	$0.0	$26.3
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.5	$0.5	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.4
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	($8.3)	$0.0	($0.2)	($8.5)	($0.0)	$0.0	$0.7	$0.7	$0.0	($7.8)
Generation	$0.0	($263.9)	$0.0	$263.9	$0.0	$17.8	$0.0	($17.8)	$0.0	$246.1
Import	$0.0	$0.2	$0.0	($0.2)	$0.0	($2.2)	($0.2)	$2.0	$0.0	$1.9
INC	$0.0	($8.3)	$0.0	$8.3	$0.0	$12.7	$0.0	($12.7)	$0.0	($4.4)
Internal Bilateral	$83.8	$83.7	($0.0)	$0.0	($0.3)	($0.3)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$22.7	$22.7	$0.0	$0.0	($29.9)	($29.9)	$0.0	($7.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.2)	$0.0	($0.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$0.0	$254.1

Table 11-12 Total PJM congestion credits and charges 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 11-13 shows the change in total congestion credits and charges incurred by transaction type from the first six months of 2018 to the first six months of 2019. Total congestion credits incurred by generation decreased by $623.8 million, and total congestion charges incurred by demand decreased by $44.9 million. The total congestion payments to up to congestion transactions (UTCs) decreased by $14.1 million, from $21.3 million in the first six months of 2018 to $7.2 million in the first six months of 2019. Total day-ahead congestion payments to UTCs decreased by $62.8 million from $40.1 million in the first six months of 2018 to -$22.7 million in the first six months of 2019. Over the same period balancing congestion payments to UTCs increased by $48.8 million, from -$18.8 million in the first six months of 2018 to $29.9 million in the first six months of 2019.

Table 11-13 Change in total PJM congestion credits and charges by transaction type by market: January through June, 2018 to 2019 (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	($5.5)	$0.0	$0.0	($5.5)	$8.6	$0.0	$0.0	$8.6	$0.0	$3.1
Demand	($14.7)	$0.0	$0.0	($14.7)	($30.1)	$0.0	$0.0	($30.1)	$0.0	($44.9)
Demand Response	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	($0.3)	($0.3)	$0.0	$0.0	$0.5	$0.5	$0.0	$0.2
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)
Export	$30.9	$0.0	$0.6	$31.5	$9.8	$0.0	$4.3	$14.1	$0.0	$45.6
Generation	$0.0	$664.9	$0.0	($664.9)	$0.0	($41.1)	$0.0	$41.1	$0.0	($623.8)
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	$6.3	$0.0	($6.3)	$0.0	$37.4	$2.8	($34.7)	$0.0	($40.9)
INC	$0.0	$8.1	$0.0	($8.1)	$0.0	($11.4)	$0.0	$11.4	$0.0	$3.3
Internal Bilateral	($122.1)	($122.5)	($0.4)	$0.0	($3.4)	($3.4)	($0.0)	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$62.8	$62.8	$0.0	$0.0	($48.8)	($48.8)	$0.0	$14.1
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.6	$0.2	($0.4)	$0.0	($0.4)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.6	$0.0	$0.0	$0.6	$0.0	$0.6
Total	($111.4)	$556.8	$63.2	($605.0)	($14.5)	($17.8)	($40.9)	($37.5)	$0.0	($642.5)

Zonal Congestion

Zonal congestion is calculated on a constraint specific basis. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. This constraint based congestion is the total congestion payments by load at the buses within a defined area minus total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of location. Constraint based congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

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

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

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of allocating the congestion of an individual constraint, the reference bus for each constraint calculation is moved to the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

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

Table 11-14 shows the day-ahead and balancing congestion by zone for the first six months of 2019. Table 11-15 shows the congestion costs by zone for the first six months of 2018.

Table 11-14 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through June, 2019

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
AECO	$2.6	($2.0)	$0.5	$5.1	$0.0	$0.4	($0.3)	($0.7)	$4.4
AEP	$17.0	($27.0)	$4.0	$48.0	$0.1	$4.5	($4.8)	($9.2)	$38.8
APS	$9.7	($11.6)	$1.0	$22.2	$0.1	$1.7	($1.9)	($3.5)	$18.7
ATSI	$6.4	($13.1)	$1.4	$20.9	($0.0)	$2.1	($2.5)	($4.6)	$16.3
BGE	$4.5	($6.6)	$0.5	$11.6	($0.1)	$1.2	($1.3)	($2.6)	$9.0
ComEd	$7.4	($25.0)	$5.5	$37.9	$0.0	$3.0	($2.4)	($5.4)	$32.5
DAY	$1.9	($3.0)	$0.4	$5.4	$0.0	$0.6	($0.7)	($1.2)	$4.1
DEOK	$3.3	($4.4)	$0.7	$8.4	$0.0	$0.9	($1.0)	($1.9)	$6.5
DLCO	$1.0	($1.8)	$0.2	$3.0	$0.0	$0.4	($0.5)	($0.9)	$2.1
Dominion	$12.5	($21.6)	$1.8	$35.8	$0.3	$3.6	($3.8)	($7.2)	$28.6
DPL	$6.4	($5.2)	$1.2	$12.8	($0.1)	$0.9	($0.8)	($1.8)	$11.0
EKPC	$1.5	($2.5)	$0.3	$4.3	$0.0	$0.5	($0.5)	($0.9)	$3.3
EXT	$0.2	($0.0)	$0.1	$0.3	($0.2)	$0.2	($1.1)	($1.6)	($1.3)
JCPL	$2.5	($7.4)	$0.5	$10.4	$0.1	$0.8	($0.8)	($1.6)	$8.8
Met-Ed	$2.6	($4.6)	$0.3	$7.5	($0.1)	$0.7	($0.7)	($1.5)	$6.0
OVEC	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.1	$0.1	$0.1
PECO	$2.7	($12.8)	$0.8	$16.3	$0.1	$1.6	($1.5)	($2.9)	$13.4
PENELEC	$4.4	($4.6)	$0.5	$9.5	($0.1)	$0.7	($0.6)	($1.4)	$8.1
Pepco	$3.9	($5.9)	$0.5	$10.3	$0.1	$1.0	($1.1)	($2.1)	$8.2
PPL	$5.3	($13.8)	$1.5	$20.6	$0.1	$1.4	($1.5)	($2.9)	$17.7
PSEG	$4.5	($14.8)	$1.0	$20.3	($0.0)	$1.7	($1.5)	($3.2)	$17.1
RECO	$0.2	($0.5)	$0.1	$0.8	($0.0)	$0.0	($0.3)	($0.4)	$0.5
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1

Table 11-15 Day-ahead and balancing congestion by zone (Dollars (Millions)): January through June, 2018

	Congestion Costs (Millions)								
	Day-Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
AECO	$1.9	($9.1)	($0.5)	$10.6	$0.2	$0.5	$0.1	($0.2)	$10.4
AEP	$47.5	($121.6)	($5.4)	$163.7	$2.1	$6.9	$1.2	($3.5)	$160.2
APS	$14.0	($40.6)	($2.6)	$52.0	$1.0	$2.3	$0.8	($0.6)	$51.4
ATSI	$15.1	($53.6)	($3.1)	$65.7	$1.0	$2.4	$0.1	($1.3)	$64.3
BGE	$10.9	($26.0)	($2.0)	$35.0	$0.7	$1.7	$0.7	($0.4)	$34.6
ComEd	$3.9	($106.9)	($1.9)	$108.9	$1.6	$5.6	$0.6	($3.3)	$105.5
DAY	$3.6	($16.3)	($0.9)	$19.0	$0.3	$0.7	$0.1	($0.3)	$18.7
DEOK	$4.7	($30.7)	($1.3)	$34.1	$0.5	$1.0	$0.2	($0.3)	$33.7
DLCO	$2.2	($9.6)	($0.6)	$11.2	$0.3	$0.5	($0.0)	($0.3)	$10.9
Dominion	$40.3	($81.2)	($6.1)	$115.4	$2.9	$6.4	$2.6	($0.9)	$114.5
DPL	$19.7	($19.5)	($0.0)	$39.1	$0.0	$0.9	($0.3)	($1.1)	$38.0
EKPC	$3.8	($14.7)	($1.0)	$17.6	$0.4	$0.7	$0.3	$0.0	$17.6
EXT	$0.1	($0.4)	$0.5	$1.0	$0.0	$5.7	$0.9	($4.7)	($3.8)
JCPL	$4.6	($23.1)	($1.4)	$26.3	$0.4	$1.0	$0.3	($0.3)	$26.0
Met-Ed	$3.3	($19.8)	($1.1)	$22.0	$0.3	$1.3	$0.3	($0.7)	$21.3
PECO	$7.2	($39.2)	($2.9)	$43.4	$0.7	$1.9	$0.7	($0.5)	$42.9
PENELEC	$0.3	($22.0)	($1.3)	$20.9	$0.2	$0.8	$0.3	($0.3)	$20.6
Pepco	$12.0	($22.7)	($1.9)	$32.8	$0.6	$1.5	$0.7	($0.2)	$32.5
PPL	$9.1	($42.7)	($4.0)	$47.8	$0.8	$1.9	$1.1	($0.0)	$47.8
PSEG	$7.4	($44.1)	($2.7)	$48.8	$0.7	$2.0	$0.5	($0.8)	$48.0
RECO	$0.3	($1.2)	($0.1)	$1.4	$0.0	$0.1	($0.0)	($0.1)	$1.4
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In these special cases the associated congestion is assigned to the control zone or residual load aggregate where the congestion is incurred and/or there are positive CLMPs from that constraint. Table 11-14 and Table 11-15 include congestion allocations from these special case constraints.

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

Table 11-16 and Table 11-17 show the allocation of total congestion by each special case allocation method, congestion allocated by the standard method and total allocation by zone. Closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. Through the assumption of artificial flexibility (an assumption of a dispatchable range where none exists) on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. Price forcing caused by the closed loop interfaces and CT pricing logic artificial constraint causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion to be associated with the constraint. None of the closed loop interfaces were binding in 2018 or in the first six months of 2019.

Table 11-16 Constraint based total day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through June, 2019

Congestion Costs (Millions)															
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.0	$0.0	$0.0	$0.0	$5.1	$5.1	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	$4.4
AEP	$0.0	($0.0)	$0.0	$1.2	($0.0)	$46.9	$48.0	($0.0)	($0.3)	$0.0	$0.0	($0.1)	($8.8)	($9.2)	$38.8
APS	$0.0	($0.0)	$0.0	$0.0	($0.0)	$22.3	$22.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.5)	($3.5)	$18.7
ATSI	$0.0	$0.0	$0.0	$0.0	$0.0	$20.9	$20.9	$0.0	($0.2)	$0.0	$0.0	$0.0	($4.4)	($4.6)	$16.3
BGE	$0.0	($0.0)	$0.0	$0.1	$0.0	$11.5	$11.6	($0.0)	$0.0	$0.0	$0.0	($0.0)	($2.6)	($2.6)	$9.0
ComEd	$0.0	($0.0)	$0.0	$1.3	($0.0)	$36.6	$37.9	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($5.2)	($5.4)	$32.5
DAY	$0.0	$0.0	$0.0	$0.0	$0.0	$5.3	$5.4	$0.0	($0.1)	$0.0	$0.0	$0.0	($1.2)	($1.2)	$4.1
DEOK	$0.0	$0.0	$0.0	$0.0	$0.0	$8.4	$8.4	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($1.9)	($1.9)	$6.5
DLCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.0	$3.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.9)	($0.9)	$2.1
Dominion	$0.0	$0.0	$0.0	$0.0	($0.0)	$35.8	$35.8	$0.0	$0.0	$0.0	($0.0)	($0.0)	($7.2)	($7.2)	$28.6
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$12.8	$12.8	($0.0)	$0.0	$0.0	$0.0	($0.1)	($1.8)	($1.8)	$11.0
EKPC	$0.0	$0.0	$0.0	$0.0	($0.0)	$4.3	$4.3	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.9)	($0.9)	$3.3
EXT	$0.0	($0.1)	$0.0	$0.2	$0.1	$0.0	$0.3	($0.0)	($1.4)	$0.0	$0.0	($0.2)	$0.0	($1.6)	($1.3)
JCPL	($0.0)	($0.0)	$0.0	$0.0	$0.0	$10.4	$10.4	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.5)	($1.6)	$8.8
Met-Ed	$0.0	$0.0	$0.0	$0.2	($0.0)	$7.3	$7.5	$0.0	$0.0	$0.0	($0.1)	$0.0	($1.4)	($1.5)	$6.0
OVEC	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.1
PECO	($0.0)	$0.0	$0.0	$0.0	($0.0)	$16.2	$16.3	($0.0)	($0.1)	$0.0	($0.0)	$0.0	($2.8)	($2.9)	$13.4
PENELEC	$0.0	($0.1)	$0.0	$0.2	($0.0)	$9.4	$9.5	$0.0	($0.0)	$0.0	($0.1)	$0.0	($1.4)	($1.4)	$8.1
Pepco	$0.0	($0.0)	$0.0	($0.0)	$0.0	$10.3	$10.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($2.1)	($2.1)	$8.2
PPL	$0.0	($0.0)	$0.0	$0.1	($0.0)	$20.5	$20.6	($0.0)	($0.1)	$0.0	$0.0	$0.0	($2.8)	($2.9)	$17.7
PSEG	($0.0)	$0.1	$0.0	$0.0	($0.0)	$20.3	$20.3	$0.0	($0.0)	$0.0	$0.0	$0.0	($3.2)	($3.2)	$17.1
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8	$0.8	$0.0	($0.3)	$0.0	$0.0	($0.0)	($0.1)	($0.4)	$0.5
Total	$0.0	($0.2)	$0.0	$3.4	$0.1	$308.2	$311.5	($0.0)	($2.6)	$0.0	($0.2)	($0.3)	($54.3)	($57.4)	$254.1

Table 11-17 Constraint Based total day-ahead and total balancing congestion assigned by zone and special case logic (Dollars (Millions)): January through June, 2018

	Congestion Costs (Millions)														
	Day-Ahead							Balancing							
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.1	$0.0	$0.3	$0.0	$10.1	$10.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.2)	$10.4
AEP	$0.3	$0.0	$0.0	$0.5	$0.0	$162.8	$163.7	$0.0	($2.1)	$0.0	$0.0	$0.0	($1.4)	($3.5)	$160.2
APS	$0.0	($0.3)	$0.0	$0.0	($0.0)	$52.3	$52.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($0.5)	($0.6)	$51.4
ATSI	$0.0	$0.5	$0.0	$0.2	$0.0	$65.0	$65.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.2)	($1.3)	$64.3
BGE	$0.0	$0.0	$0.0	$0.0	$0.0	$35.0	$35.0	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($0.3)	($0.4)	$34.6
ComEd	$1.4	($1.0)	$0.0	$4.1	($0.0)	$104.3	$108.9	($0.0)	($1.9)	$0.0	$0.3	$0.3	($2.1)	($3.3)	$105.5
DAY	$0.0	$0.1	$0.0	$0.0	$0.0	$18.9	$19.0	$0.0	($0.2)	$0.0	$0.0	$0.2	($0.3)	($0.3)	$18.7
DEOK	$0.2	$0.2	$0.0	$2.0	$0.0	$31.8	$34.1	$0.0	$0.1	$0.0	$0.0	$0.2	($0.6)	($0.3)	$33.7
DLCO	$0.0	$0.0	$0.0	$0.0	($0.0)	$11.2	$11.2	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.2)	($0.3)	$10.9
Dominion	$0.0	$0.2	$0.0	$0.2	$0.0	$115.0	$115.4	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.9)	($0.9)	$114.5
DPL	$0.0	$0.6	$0.0	$0.3	$0.0	$38.2	$39.1	$0.0	($0.1)	$0.0	$0.0	($0.0)	($1.0)	($1.1)	$38.0
EKPC	$0.0	$0.0	$0.0	$0.0	$0.0	$17.6	$17.6	$0.0	($0.0)	$0.0	$0.0	$0.1	($0.1)	$0.0	$17.6
EXT	$0.0	$0.1	$0.0	$0.5	$0.3	$0.0	$1.0	$0.0	($3.8)	$0.0	$0.0	($1.0)	$0.0	($4.7)	($3.8)
JCPL	$0.0	$0.7	$0.0	($0.0)	$0.0	$25.5	$26.3	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	$26.0
Met-Ed	$0.0	$0.2	$0.0	$3.0	$0.0	$18.8	$22.0	$0.0	($0.0)	$0.0	($0.5)	$0.0	($0.1)	($0.7)	$21.3
PECO	$0.0	($0.7)	$0.0	$0.4	($0.0)	$43.7	$43.4	$0.0	($0.1)	$0.0	$0.0	$0.0	($0.4)	($0.5)	$42.9
PENELEC	$0.3	$0.1	$0.0	$0.7	($0.0)	$19.7	$20.9	$0.0	$0.1	$0.0	($0.0)	$0.0	($0.5)	($0.3)	$20.6
Pepco	$0.0	$0.1	$0.0	$0.0	$0.0	$32.6	$32.8	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.3)	($0.2)	$32.5
PPL	($0.0)	($2.0)	$0.0	$0.8	($0.0)	$49.0	$47.8	$0.0	$0.1	$0.0	$0.0	$0.0	($0.1)	($0.0)	$47.8
PSEG	$0.0	($0.3)	$0.0	$0.7	($0.0)	$48.4	$48.8	$0.0	($0.0)	$0.0	$0.0	($0.1)	($0.7)	($0.8)	$48.0
RECO	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$1.4	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	($0.1)	$1.4
Total	$2.3	($1.2)	$0.0	$13.9	$0.3	$901.2	$916.5	($0.0)	($8.2)	$0.0	($0.2)	($0.3)	($11.2)	($19.9)	$896.6

Monthly Congestion

Table 11-18 shows day-ahead, balancing and inadvertent congestion costs by month for 2018 and the first six months of 2019.

Table 11-18 Monthly PJM congestion costs by market (Dollars (Millions)): January 2018 through June 2019

	Congestion Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$517.7	$18.2	$0.0	$535.9	$120.7	($20.6)	$0.0	$100.2
Feb	$43.8	$1.4	($0.0)	$45.2	$36.4	($5.5)	$0.0	$30.9
Mar	$80.2	($0.3)	$0.0	$79.9	$45.0	($12.2)	$0.0	$32.8
Apr	$57.4	($3.3)	$0.0	$54.1	$25.4	($3.2)	$0.0	$22.2
May	$122.2	($16.0)	$0.0	$106.2	$47.5	($9.5)	($0.0)	$38.0
Jun	$95.2	($19.9)	$0.0	$75.3	$36.4	($6.5)	$0.0	$29.9
Jul	$70.8	($5.8)	$0.0	$65.0				
Aug	$69.2	($3.5)	$0.0	$65.7				
Sep	$95.2	($6.3)	($0.0)	$88.9				
Oct	$95.0	($11.8)	($0.0)	$83.3				
Nov	$69.1	($14.2)	($0.0)	$54.9				
Dec	$63.0	($7.6)	$0.0	$55.5				
Total	$1,378.9	($69.0)	$0.0	$1,309.9	$311.5	($57.4)	$0.0	$254.1

Figure 11-2 shows PJM monthly total congestion cost for January 1, 2008 through June 30, 2019.

Figure 11-2 PJM monthly total congestion cost (Dollars (Millions)): January 2008 through June 2019

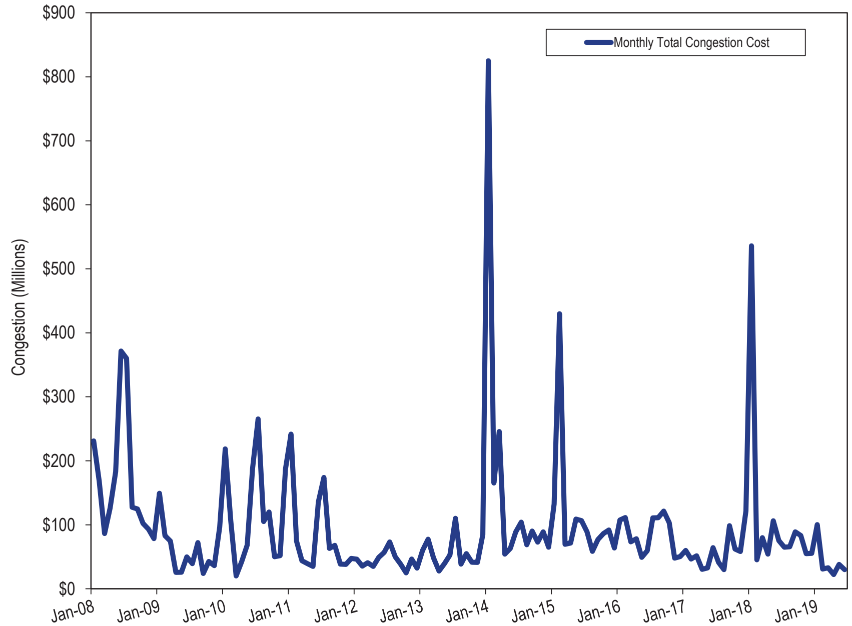


Table 11-19 shows monthly total congestion credits and charges for each virtual transaction type in 2018 and the first six months of 2019. Virtual transaction congestion charges, when positive, are the total congestion charges to the virtual transactions and when negative, are the total congestion credits to the virtual transactions. The negative totals in Table 11-19 show that virtuals were paid, in net, congestion credits in the first six months of 2019 and in the first six months of 2018. More than half the total payment to virtuals went to UTCs in the first six months of 2018 and in the first six months of 2019.

Table 11-19 Monthly PJM congestion charges by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 2019

		Congestion Costs (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$4.1	($6.5)	($2.4)	$4.5	($8.1)	($3.6)	($40.8)	$29.5	($11.3)	($17.2)
	Feb	$1.8	$0.4	$2.2	$1.2	($0.8)	$0.4	($0.5)	$1.3	$0.9	$3.5
	Mar	$0.9	($2.8)	($1.9)	$1.4	($3.2)	($1.8)	($5.1)	$2.0	($3.1)	($6.8)
	Apr	$0.4	($0.7)	($0.4)	$1.8	($1.4)	$0.4	($1.0)	$1.0	($0.1)	($0.1)
	May	$1.5	($4.1)	($2.6)	$4.5	($6.9)	($2.5)	$1.7	($10.6)	($8.9)	($14.0)
	Jun	$3.6	($2.4)	$1.1	$3.0	($3.7)	($0.7)	$5.6	($4.4)	$1.2	$1.6
	Jul	$1.3	($2.4)	($1.1)	$0.8	($0.7)	$0.1	$2.3	($2.8)	($0.5)	($1.5)
	Aug	$2.4	($3.1)	($0.6)	$0.2	($0.2)	$0.1	$3.4	($2.8)	$0.7	$0.1
	Sep	$2.1	($1.6)	$0.5	$1.4	($1.5)	($0.1)	$4.8	($6.9)	($2.1)	($1.7)
	Oct	$1.5	($2.6)	($1.1)	$2.4	($3.2)	($0.8)	$2.5	($3.3)	($0.8)	($2.7)
	Nov	$2.1	($3.3)	($1.2)	$0.4	($2.3)	($1.9)	$4.3	($7.5)	($3.2)	($6.3)
	Dec	$3.7	($3.5)	$0.1	($1.2)	$2.0	$0.8	$3.4	($3.5)	($0.1)	$0.8
	Total	$25.3	($32.7)	($7.4)	$20.5	($30.0)	($9.5)	($19.4)	($7.9)	($27.4)	($44.3)
2019	Jan	$3.5	($4.0)	($0.6)	$1.2	($3.6)	($2.4)	$5.1	($4.6)	$0.5	($2.5)
	Feb	$0.8	($1.4)	($0.6)	$1.0	($1.1)	($0.1)	$2.0	($3.2)	($1.2)	($1.8)
	Mar	$0.7	($1.5)	($0.7)	$1.4	($2.3)	($0.8)	$4.0	($8.4)	($4.4)	($6.0)
	Apr	$0.6	($0.1)	$0.5	$1.1	($1.4)	($0.3)	$2.8	($2.3)	$0.5	$0.7
	May	$0.4	($0.0)	$0.4	$2.4	($3.0)	($0.6)	$5.4	($6.3)	($0.9)	($1.2)
	Jun	$0.8	($0.6)	$0.2	$1.2	($1.3)	($0.2)	$3.3	($5.0)	($1.7)	($1.7)
	Total	$6.7	($7.5)	($0.8)	$8.3	($12.7)	($4.4)	$22.7	($29.9)	($7.2)	($12.5)

Congested Facilities

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

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first six months of 2019, there were 51,990 day-ahead, congestion event hours compared to 81,854 day-ahead congestion event hours in the first six months of 2018. Of the day-ahead congestion event hours in the first six months of 2019, only 3,189 (6.1 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2019, there were 8,287 real-time, congestion event hours compared to 12,867 real-time, congestion event hours in the first six months of 2018. Of the real-time congestion event hours in the first six months of 2019, 3,263 (39.4 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $88.6 million, or 34.9 percent, of the total PJM congestion costs in the first six months of 2019. The top five constraints were the Conastone - Peach Bottom Line, the Siegfried Transformer, the AP South Interface, the East Interface, and the CPL - DOM Interface.

The change in the location of the top 10 constraints between the first six months of 2018 and the first six months of 2019 was a result of the high gas prices in January 2018 (Figure 11-3).

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities largely as a result of the decrease in cleared up to congestion (UTC) transactions from January and February, 2018, to January and February, 2019.[20]

Real-time, congestion event hours decreased on transformers, flowgates, interfaces and lines in the first six months of 2019.

20 162 FERC ¶ 61,139.

Day-ahead congestion costs decreased on all types of facilities in the first six months of 2019 compared to the first six months of 2018. Day-ahead negative generation credits decreased on all types of facilities in the first six months of 2019 compared to the first six months of 2018.

Balancing congestion costs decreased on all types of facilities except lines in the first six months of 2019 compared to the first six months of 2018 (Table 11-21). Table 11-20 provides congestion event hour subtotals and congestion cost subtotals comparing the first six months of 2019 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[21] [22]

Table 11-20 Congestion summary (By facility type): January through June, 2019

	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	($7.9)	($41.0)	$3.1	$36.3	$0.7	$2.3	($20.2)	($21.8)	$14.5	5,799	2,373
Interface	$7.3	($32.8)	$0.1	$40.2	$1.1	$4.1	$0.7	($2.3)	$37.9	639	130
Line	$81.7	($70.9)	$15.3	$167.9	($0.8)	$12.5	($7.1)	($20.3)	$147.5	32,473	4,533
Transformer	$15.2	($30.1)	$3.0	$48.4	($1.8)	$5.8	($1.7)	($9.3)	$39.1	10,182	656
Other	$4.0	($13.4)	$1.2	$18.7	$0.8	$3.2	($1.0)	($3.4)	$15.3	2,897	595
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($0.3)	($0.3)	($0.2)	NA	NA
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	51,990	8,287

Table 11-21 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)	$4.6	$6.2	$1.1	$169.4	12,857	3,445
Interface	$60.1	($161.4)	($13.7)	$207.8	$15.2	$22.8	$11.1	$3.5	$211.3	1,951	373
Line	$126.5	($245.8)	$8.8	$381.1	($3.4)	$18.3	($4.7)	($26.4)	$354.8	43,813	7,631
Transformer	$52.0	($87.9)	$1.1	$141.0	($0.5)	$0.8	$3.5	$2.2	$143.2	20,213	1,009
Other	$12.7	($4.2)	$1.0	$17.9	$3.0	($1.6)	($4.7)	($0.0)	$17.9	3,020	409
Unclassified	$0.1	($0.1)	$0.1	$0.3	$0.9	$0.9	($0.3)	($0.3)	$0.0	NA	NA
Total	$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	81,854	12,867

Table 11-22 and Table 11-23 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-22. In the first six months of 2019, there were 51,990 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 3,189 (6.1

21 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.

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

percent) were also constrained in the Real-Time Energy Market. In the first six months of 2018, of the 81,854 day-ahead congestion event hours, only 6,423 (7.8 percent) were binding in the Real-Time Energy Market.[23]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-23. In the first six months of 2019, of the 8,287 congestion event hours in the Real-Time Energy Market, 3,263 (39.4 percent) were also constrained in the Day-Ahead Energy Market. In the first six months of 2018, of the 12,867 real-time congestion event hours, 6,482 (50.4 percent) were also in the Day-Ahead Energy Market.

Table 11-22 Congestion event hours (day-ahead against real-time): January through June, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	12,857	1,538	12.0%	5,799	451	7.8%
Interface	1,951	238	12.2%	639	27	4.2%
Line	43,813	4,014	9.2%	32,473	2,136	6.6%
Transformer	20,213	405	2.0%	10,182	343	3.4%
Other	3,020	228	7.5%	2,897	232	8.0%
Total	81,854	6,423	7.8%	51,990	3,189	6.1%

Table 11-23 Congestion event hours (real-time against day-ahead): January through June, 2018 and 2019

	Congestion Event Hours					
	2018 (Jan - Jun)			2019 (Jan - Jun)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	3,445	1,538	44.6%	2,373	450	19.0%
Interface	373	263	70.5%	130	31	23.8%
Line	7,631	4,047	53.0%	4,533	2,192	48.4%
Transformer	1,009	406	40.2%	656	344	52.4%
Other	409	228	55.7%	595	246	41.3%
Total	12,867	6,482	50.4%	8,287	3,263	39.4%

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

Table 11-24 shows congestion costs by facility voltage class for the first six months of 2019. Congestion costs in the first six months of 2019 decreased for all facilities except 69 kV facilities compared to the first six months of 2018.

Table 11-24 Congestion summary (By facility voltage): January through June, 2019

	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	($0.1)	($0.7)	$0.6	$1.2	($0.1)	$0.2	($0.2)	($0.5)	$0.7	171	46
500	$43.1	($38.7)	$0.1	$81.9	$2.0	$6.4	($1.2)	($5.7)	$76.2	2,907	1,450
345	($2.7)	($32.8)	$5.5	$35.6	$0.6	$0.8	($4.6)	($4.8)	$30.8	5,949	561
230	$34.0	($50.1)	$3.5	$87.5	($2.2)	$10.1	($4.1)	($16.4)	$71.1	7,067	1,980
212	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	114	0
161	($0.2)	($4.6)	($0.1)	$4.3	($0.2)	$0.1	($0.3)	($0.6)	$3.7	1,041	107
138	$11.0	($43.8)	$9.8	$64.5	$0.1	$3.1	($17.9)	($20.8)	$43.7	15,888	2,988
115	$5.7	($12.3)	$0.5	$18.5	($0.5)	$5.9	($0.7)	($7.1)	$11.3	5,059	725
69	$9.2	($5.4)	$2.9	$17.6	$0.4	$1.2	($0.3)	($1.1)	$16.5	12,583	430
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
34	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	620	0
13	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	490	0
12	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	84	0
Unclassified	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($0.3)	($0.3)	($0.2)	NA	NA
Total	$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	51,990	8,287

Table 11-25 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	($0.0)	$0.4	$2.4	94	21
500	$65.3	($168.7)	($13.3)	$220.7	$14.5	$19.8	$11.9	$6.6	$227.2	2,714	556
345	$23.3	($191.0)	($5.2)	$209.1	($1.0)	($3.3)	($2.3)	$0.0	$209.1	14,998	1,540
230	$127.4	($26.1)	$2.9	$156.4	$0.0	$5.7	$0.2	($5.5)	$150.9	14,217	3,639
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	($0.2)	$19.6	$2.3	($17.6)	$253.9	31,554	5,484
115	$1.6	($40.7)	($3.7)	$38.6	$0.1	$3.9	($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	($0.0)	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	NA	NA
Total	$211.6	($745.0)	($40.4)	$916.3	$13.8	$44.9	$11.5	($19.6)	$896.6	81,854	12,867

Constraint Duration

Table 11-26 lists the constraints for January through June, 2018 and 2019 that were most frequently binding and Table 11-27 shows the constraints which experienced the largest change in congestion event hours from the first six months of 2018 to the first six months of 2019. In Table 11-26, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first six months of 2019. In Table 11-27, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first six months of 2018 to the first six months of 2019.

Table 11-26 Top 25 constraints with frequent occurrence: January through June, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Jun)			Real-Time (Jan - Jun)			Day-Ahead (Jan - Jun)			Real-Time (Jan - Jun)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Conastone - Peach Bottom	Line	352	2,159	1,807	125	1,188	1,063	8%	50%	42%	3%	27%	24%
2	Monroe - Vineland	Line	545	2,641	2,096	29	78	49	13%	61%	48%	1%	2%	1%
3	Berwick - Koonsville	Line	358	2,666	2,308	0	2	2	8%	61%	53%	0%	0%	0%
4	Easton - Emuni	Line	1,874	1,814	(60)	2	9	7	43%	42%	(1%)	0%	0%	0%
5	Face Rock	Other	402	1,653	1,251	0	0	0	9%	38%	29%	0%	0%	0%
6	Marquis - Dept of Energy	Line	118	1,494	1,376	0	0	0	3%	34%	32%	0%	0%	0%
7	Gardners - Texas Eastern	Line	1,829	1,028	(801)	292	92	(200)	42%	24%	(18%)	7%	2%	(5%)
8	Munster	Flowgate	0	709	709	0	169	169	0%	16%	16%	0%	4%	4%
9	Siegfried	Trf	2	560	558	9	310	301	0%	13%	13%	0%	7%	7%
10	Marblehead	Flowgate	202	551	349	335	260	(75)	5%	13%	8%	8%	6%	(2%)
11	Graceton - Safe Harbor	Line	2,889	605	(2,284)	1,755	205	(1,550)	67%	14%	(53%)	40%	5%	(36%)
12	Lenox - North Meshoppen	Line	27	425	398	1	350	349	1%	10%	9%	0%	8%	8%
13	East Towanda - Hillside	Line	199	454	255	2	290	288	5%	10%	6%	0%	7%	7%
14	Goodland - Reynolds	Flowgate	36	103	67	8	608	600	1%	2%	2%	0%	14%	14%
15	Palisades - Argenta	Flowgate	0	618	618	0	69	69	0%	14%	14%	0%	2%	2%
16	New Castle	Trf	195	686	491	0	0	0	4%	16%	11%	0%	0%	0%
17	Roxana - Praxair	Flowgate	497	512	15	263	131	(132)	11%	12%	0%	6%	3%	(3%)
18	Hazard	Trf	140	624	484	17	0	(17)	3%	14%	11%	0%	0%	(0%)
19	Tristate	Trf	0	597	597	0	23	23	0%	14%	14%	0%	1%	1%
20	New Carlisle - Olive	Line	109	579	470	0	0	0	3%	13%	11%	0%	0%	0%
21	Preston - Tanyard	Line	244	579	335	4	0	(4)	6%	13%	8%	0%	0%	(0%)
22	Tanners Creek - Miami Fort	Flowgate	958	562	(396)	0	0	0	22%	13%	(9%)	0%	0%	0%
23	Vermilion - Tilton	Flowgate	148	546	398	0	0	0	3%	13%	9%	0%	0%	0%
24	Mountain	Trf	379	499	120	0	0	0	9%	11%	3%	0%	0%	0%
25	Emilie - Falls	Line	751	393	(358)	149	95	(54)	17%	9%	(8%)	3%	2%	(1%)

Table 11-27 Top 25 constraints with largest year to year change in occurrence: January through June, 2018 and 2019

			Event Hours						Percent of Annual Hours					
			Day-Ahead (Jan - Jun)			Real-Time (Jan - Jun)			Day-Ahead (Jan - Jun)			Real-Time (Jan - Jun)		
No.	Constraint	Type	2018	2019	Change	2018	2019	Change	2018	2019	Change	2018	2019	Change
1	Graceton - Safe Harbor	Line	2,889	605	(2,284)	1,755	205	(1,550)	67%	14%	(53%)	40%	5%	(36%)
2	Conastone - Peach Bottom	Line	352	2,159	1,807	125	1,188	1,063	8%	50%	42%	3%	27%	24%
3	Berwick - Koonsville	Line	358	2,666	2,308	0	2	2	8%	61%	53%	0%	0%	0%
4	Monroe - Vineland	Line	545	2,641	2,096	29	78	49	13%	61%	48%	1%	2%	1%
5	Quad Cities	Trf	2,026	312	(1,714)	0	0	0	47%	7%	(39%)	0%	0%	0%
6	Lakeview - Greenfield	Line	1,303	36	(1,267)	321	13	(308)	30%	1%	(29%)	7%	0%	(7%)
7	Brokaw - Leroy	Flowgate	1,232	0	(1,232)	261	0	(261)	28%	0%	(28%)	6%	0%	(6%)
8	Marquis - Dept of Energy	Line	118	1,494	1,376	0	0	0	3%	34%	32%	0%	0%	0%
9	Olive	Other	1,327	0	(1,327)	0	0	0	31%	0%	(31%)	0%	0%	0%
10	Face Rock	Other	402	1,653	1,251	0	0	0	9%	38%	29%	0%	0%	0%
11	Newton	Flowgate	858	0	(858)	367	0	(367)	20%	0%	(20%)	8%	0%	(8%)
12	Flint Lake - Luchtman Road	Flowgate	865	0	(865)	354	0	(354)	20%	0%	(20%)	8%	0%	(8%)
13	Zion	Line	1,193	0	(1,193)	0	0	0	27%	0%	(27%)	0%	0%	0%
14	Waukegan	Trf	1,083	19	(1,064)	0	0	0	25%	0%	(24%)	0%	0%	0%
15	Cedar Grove Sub - Roseland	Line	1,198	179	(1,019)	54	15	(39)	28%	4%	(23%)	1%	0%	(1%)
16	Gardners - Texas Eastern	Line	1,829	1,028	(801)	292	92	(200)	42%	24%	(18%)	7%	2%	(5%)
17	Pleasant Prairie - Zion	Flowgate	1,011	117	(894)	60	0	(60)	23%	3%	(21%)	1%	0%	(1%)
18	Canton - South Troy	Line	949	0	(949)	0	0	0	22%	0%	(22%)	0%	0%	0%
19	Person - Sedge Hill	Line	814	17	(797)	136	10	(126)	19%	0%	(18%)	3%	0%	(3%)
20	Monroe - Lallendorf	Flowgate	945	62	(883)	0	0	0	22%	1%	(20%)	0%	0%	0%
21	Munster	Flowgate	0	709	709	0	169	169	0%	16%	16%	0%	4%	4%
22	Siegfried	Trf	2	560	558	9	310	301	0%	13%	13%	0%	7%	7%
23	Lenox - North Meshoppen	Line	27	425	398	1	350	349	1%	10%	9%	0%	8%	8%
24	Halifax - Roanoke Rapids	Line	741	0	(741)	0	0	0	17%	0%	(17%)	0%	0%	0%
25	AEP - DOM	Int	604	23	(581)	150	0	(150)	14%	1%	(13%)	3%	0%	(3%)

Constraint Costs

Table 11-28 and Table 11-29 show the top constraints affecting congestion costs by facility for the first six months of 2019 and 2018. The Conastone - Peach Bottom Line was the largest contributor to congestion costs in the first six months of 2019, with $40.7 million in total congestion costs and 16.0 percent of the total PJM congestion costs in the first six months of 2019.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2019[24]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2019 (Jan - Jun)
1	Conastone - Peach Bottom	Line	500	$36.5	($4.0)	($0.1)	$40.3	$0.9	$2.0	$1.4	$0.4	$40.7	16.0%
2	Siegfried	Transformer	PPL	$6.8	($13.7)	$0.4	$20.9	($1.6)	$5.2	($0.1)	($6.8)	$14.1	5.5%
3	AP South	Interface	500	$8.3	($5.5)	($0.2)	$13.6	$0.2	$0.1	$0.1	$0.1	$13.8	5.4%
4	East	Interface	500	($5.9)	($20.2)	$0.1	$14.4	$0.9	$4.0	$0.9	($2.2)	$12.2	4.8%
5	CPL - DOM	Interface	500	$3.5	($4.2)	$0.1	$7.8	$0.0	$0.0	$0.0	$0.0	$7.8	3.1%
6	Face Rock	Other	PPL	$0.0	($8.0)	$0.7	$8.7	$0.9	$1.6	($0.2)	($0.9)	$7.8	3.1%
7	Palisades - Argenta	Flowgate	MISO	($0.3)	($7.3)	$0.6	$7.6	$0.1	($0.3)	($0.6)	($0.3)	$7.3	2.9%
8	Tanners Creek - Miami Fort	Flowgate	MISO	($2.3)	($8.9)	$0.3	$6.9	$0.0	$0.0	$0.0	$0.0	$6.9	2.7%
9	Conastone - Northwest	Line	BGE	$4.6	($1.8)	$0.4	$6.8	($0.0)	($0.1)	($0.3)	($0.2)	$6.7	2.6%
10	Pleasant View - Ashburn	Line	Dominion	$4.7	($1.2)	$0.3	$6.2	$0.4	$0.9	($0.2)	($0.7)	$5.5	2.2%
11	Graceton - Safe Harbor	Line	BGE	$5.4	$0.0	$0.1	$5.5	$0.2	$0.4	$0.1	($0.1)	$5.4	2.1%
12	Bagley - Graceton	Line	BGE	$3.4	($1.0)	$0.1	$4.5	$0.0	$0.1	($0.0)	($0.0)	$4.5	1.8%
13	Cedar Grove Sub - Roseland	Line	PSEG	($0.0)	($4.6)	($0.3)	$4.2	($0.0)	$0.1	$0.0	($0.1)	$4.1	1.6%
14	Gardners - Texas Eastern	Line	Met-Ed	($0.4)	($5.4)	$0.2	$5.3	($0.8)	$0.3	($0.3)	($1.5)	$3.8	1.5%
15	Cloverdale	Transformer	AEP	$1.5	($1.8)	$0.3	$3.6	$0.0	($0.2)	($0.1)	$0.1	$3.7	1.5%
16	Siegfried	Other	PPL	$0.0	($5.0)	$0.5	$5.6	($0.3)	$1.1	($0.6)	($2.0)	$3.5	1.4%
17	Blooming Grove - Paupack	Line	PPL	$1.2	($2.3)	($0.0)	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	1.4%
18	Nottingham	Other	PECO	$4.1	$0.6	($0.1)	$3.3	$0.0	$0.0	$0.0	$0.0	$3.3	1.3%
19	Munster	Flowgate	MISO	($0.1)	($2.0)	($0.3)	$1.6	$0.3	($0.2)	($5.1)	($4.6)	($3.0)	(1.2%)
20	Greentown	Flowgate	MISO	($0.1)	($0.8)	($0.0)	$0.6	($0.5)	$0.3	($2.8)	($3.6)	($3.0)	(1.2%)
21	Monroe - Vineland	Line	AECO	$3.3	$1.2	$0.5	$2.7	($0.1)	($0.0)	$0.0	($0.1)	$2.6	1.0%
22	Wescosville	Transformer	PPL	$1.8	($1.0)	($0.0)	$2.7	($0.1)	$0.1	$0.0	($0.2)	$2.5	1.0%
23	Hazard	Transformer	AEP	$0.3	($2.2)	$0.0	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1.0%
24	Krendale - Shanorma	Line	APS	($2.1)	($4.3)	$0.3	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	1.0%
25	Volunteer - Phipps Bend	Flowgate	TVA	($0.2)	($0.9)	$0.0	$0.7	($0.1)	$0.3	($2.8)	($3.2)	($2.5)	(1.0%)
	Top 25 Total			$74.0	($104.4)	$3.8	$182.2	$0.5	$15.7	($10.7)	($25.9)	$156.3	61.5%
	All Other Constraints			$26.4	($83.8)	$19.1	$129.3	($0.3)	$12.3	($18.9)	($31.5)	$97.8	38.5%
	Total			$100.4	($188.3)	$22.9	$311.5	$0.2	$28.0	($29.7)	($57.4)	$254.1	100.0%

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

Table 11-29 Top 25 constraints affecting PJM congestion costs (By facility): January through June, 2018[25]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
				Load	Generation	Explicit		Load	Generation	Explicit		Grand	
No.	Constraint	Type	Location	Payments	Credits	Costs	Total	Payments	Credits	Costs	Total	Total	2018 (Jan - Jun)
1	AEP - DOM	Interface	500	$54.5	($66.2)	($5.1)	$115.6	$13.4	$18.7	$9.0	$3.8	$119.4	13.3%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	9.8%
3	Graceton - Safe Harbor	Line	BGE	$86.9	$29.2	$2.3	$60.1	($0.1)	$4.4	($1.5)	($5.9)	$54.1	6.0%
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)	$0.3	$1.9	$25.8	2.9%
7	Lakeview - Greenfield	Line	ATSI	($19.5)	($55.4)	($1.6)	$34.3	($1.4)	$8.9	$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	$0.6	$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	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.8%
12	Gardners - Texas Eastern	Line	Met-Ed	($5.7)	($20.1)	($0.1)	$14.4	$0.2	($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	$13.5	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)	$2.9	$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	$0.1	$0.5	($0.9)	($1.2)	$9.5	1.1%
19	Conastone - Northwest	Line	BGE	$8.0	($1.0)	($0.7)	$8.3	($0.8)	($0.4)	$1.4	$0.9	$9.2	1.0%
20	Flint Lake - Luchtman Road	Flowgate	MISO	$0.3	($10.4)	($4.9)	$5.7	($0.2)	($1.4)	$1.8	$3.1	$8.7	1.0%
21	Conastone - Peach Bottom	Line	500	$7.9	$0.3	$0.1	$7.8	$0.2	$0.1	($0.2)	($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%
	Top 25 Total			$193.4	($440.4)	($35.3)	$598.5	$11.1	$26.6	$24.0	$8.6	$607.1	67.7%
	All Other Constraints			$18.4	($304.6)	($5.0)	$318.0	$3.5	$19.2	($12.8)	($28.4)	$289.5	32.3%
	Total			$211.8	($745.0)	($40.3)	$916.5	$14.7	$45.8	$11.2	($19.9)	$896.6	100.0%

Figure 11-3 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 2019. Figure 11-4 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 2019.

Figure 11-5 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 2019.

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

Figure 11-3 Location of the top 10 constraints by PJM total congestion costs: January through June, 2019

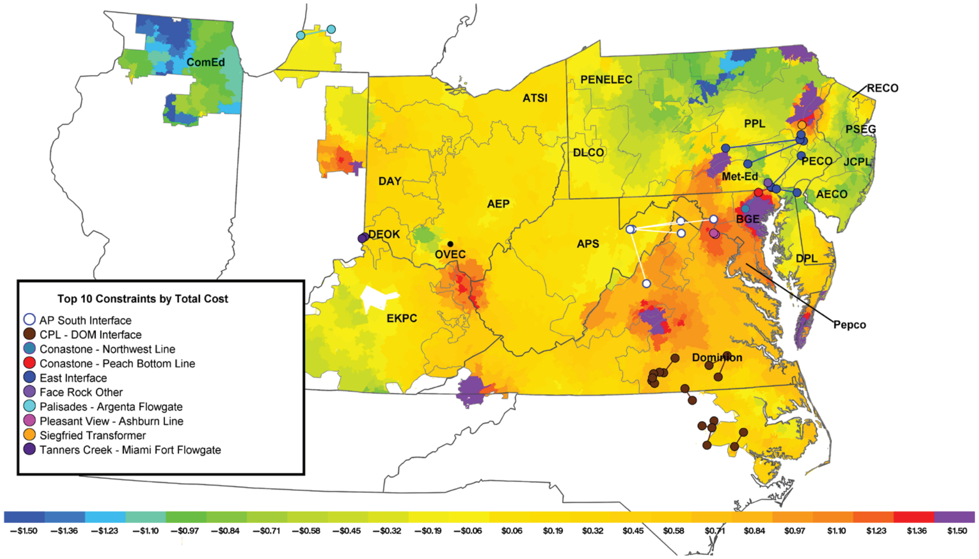


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: January through June, 2019

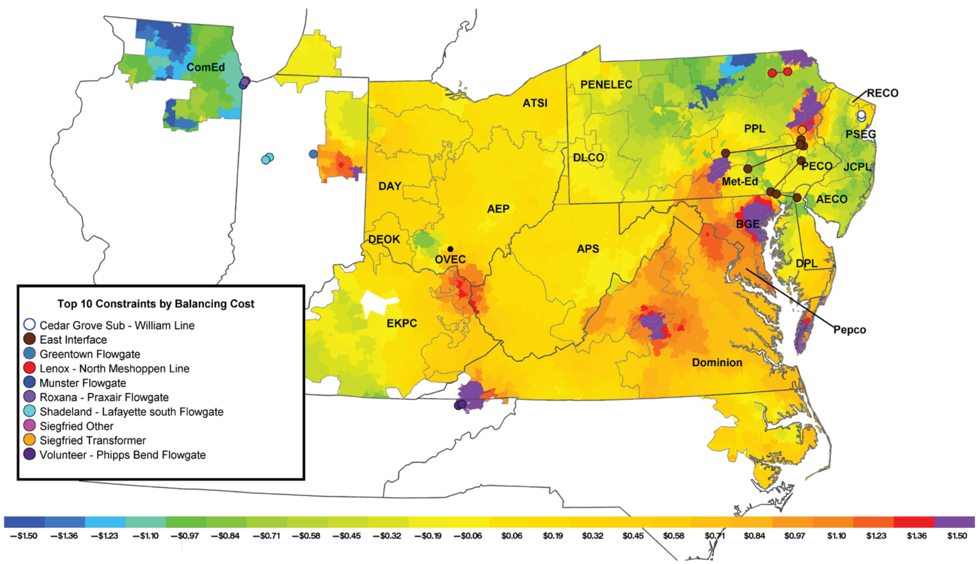
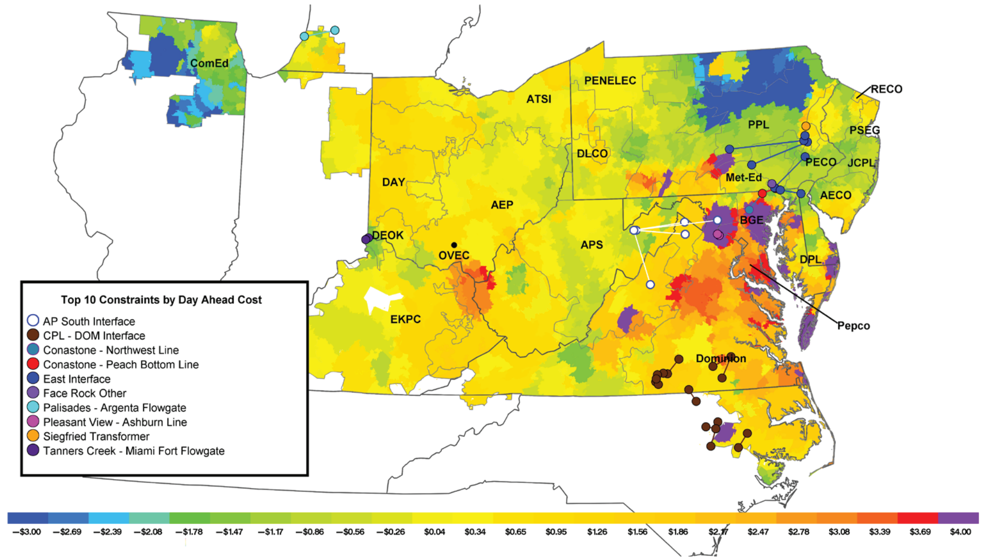


Figure 11-5 Location of the top 10 constraints by PJM day-ahead congestion costs: January through June, 2019



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.

Figure 11-6 shows that day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined as a result of a FERC order, and increased after December 7, 2015, when UTC activity increased, as a result of a FERC order. Figure 11-6 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined, as a result of a FERC order.

In the first six months of 2019, the average hourly cleared UTC MW decreased in January and February, compared to January and February, 2018. Day-ahead congestion event hours decreased by 36.5 percent from 81,854 congestion event hours in the first six months of 2018 to 51,990 congestion event hours in the first six months of 2019 (Table 11-22). The majority (94.2 percent) of decrease in day-ahead congestion event hours in the first six months of 2019 occurred in January and February.

Figure 11-6 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through June 30, 2019.

Figure 11-6 Daily congestion event hours: January 2014 through June 2019

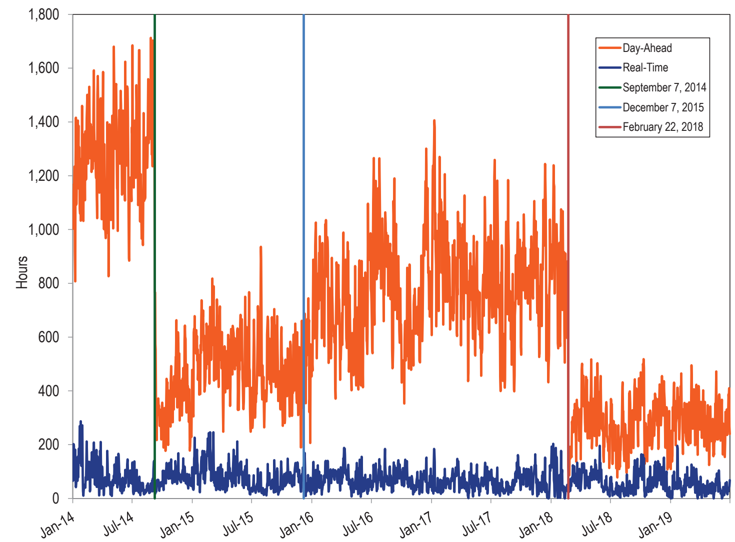
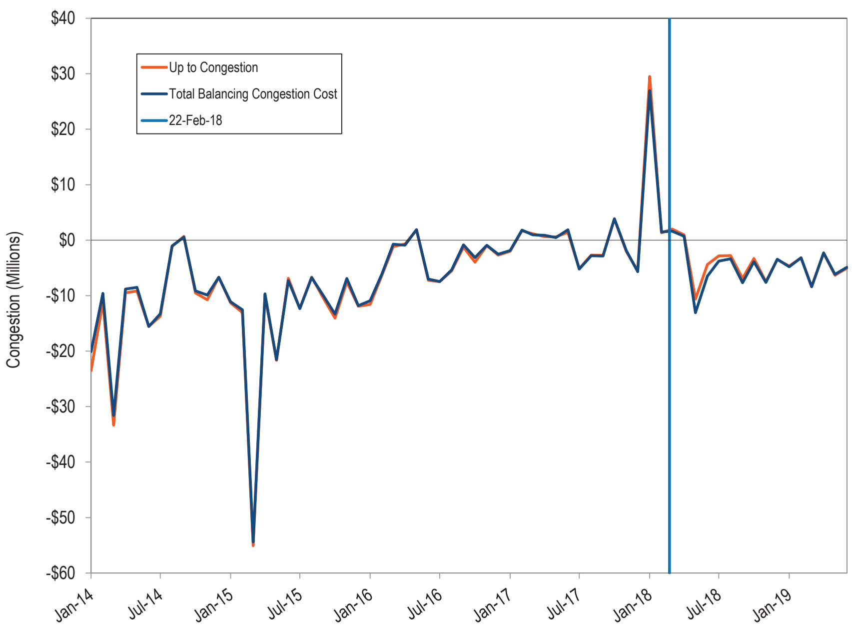


Figure 11-7 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014, through December 31, 2018. Within this period, Figure 11-7 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January 2018. Figure 11-7 shows that UTCs are a significant net contributor to balancing congestion in PJM. As shown in Figure 11-7, UTCs are generally paid balancing congestion, which takes the form of negative balancing congestion charges being allocated to UTC positions.

Figure 11-7 Monthly balancing congestion cost incurred by up to congestion: January 2014 through June 2019



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

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

Table 11-30 provides an example of how UTCs can interact with, and profit from, differences in day-ahead and real-time transmission limits and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

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

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

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

Table 11-30 shows the balancing credits and charges generated by the real-time deviations by source in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250, with net total congestion credits (payments) to generation and the UTC exceeding the total charges collected from load. The negative balance owed to generation and the UTC is billed to the load as negative balancing congestion, under the recent FERC order.

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

Table 11-30 Example of UTC causing and profiting from negative balancing congestion

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

Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[26] 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.[27] 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.

26 PJM Operating Agreement Schedule 1 §3.7.
27 *Id.*

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.[28]

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[29]

28 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25. 2018).
29 PJM. Operating Agreement Schedule 1 §3.7.

Total Marginal Loss Cost

The total marginal loss cost in PJM for the first six months of 2019 was $323.1 million, which was comprised of load loss payments of -$22.9 million, generation loss credits of -$352.6 million, explicit loss costs of -$6.6 million and inadvertent loss charges of $0.0 million (Table 11-32).

Monthly marginal loss costs in the first six months of 2019 ranged from $38.8 million in April to $86.5 million in January. Total marginal loss surplus decreased in the first six months of 2019 by $71.4 million or 40.7 percent from $175.6 million in the first six months of 2018 to $104.2 million in the first six months of 2019.

Table 11-31 shows the total marginal loss component costs and the total PJM billing for January through June, 2008 through 2019.

Table 11-31 Total PJM loss component costs (Dollars (Millions)): January through June, 2008 through 2019[30]

(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%
2019	$323	(38.0%)	$20,070	1.6%

Table 11-32 shows PJM total marginal loss costs by accounting category for January through June, 2008 through 2019. Table 11-33 shows PJM total marginal loss costs by accounting category by market for January through June, 2008 through 2019.

30 The loss costs include net inadvertent charges.

Table 11-32 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through June, 2008 through 2019

	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	($31.9)	($559.3)	($6.0)	$0.0	$521.4
2019	($22.9)	($352.6)	($6.6)	$0.0	$323.1

Table 11-33 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through June, 2008 through 2019

	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	($35.3)	($553.0)	$16.7	$534.4	$3.4	($6.3)	($22.7)	($12.9)	$0.0	$521.4
2019	($23.0)	($350.2)	$22.6	$349.7	$0.1	($2.4)	($29.2)	($26.6)	$0.0	$323.1

Table 11-34 and Table 11-35 show the total loss costs for each transaction type in the first six months of 2019 and 2018. In the first six months of 2019, generation paid loss costs of $339.6 million, 105.1 percent of total loss costs. In the first six months of 2018, generation paid loss costs of $522.6 million, 100.2 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 2019, DECs were paid $2.2 million in loss credits in the day-ahead market, paid $2.8 million in loss costs in the balancing energy market and paid $0.6 million in total loss payments. In the first six months of 2019, INCs paid $5.4 million in loss costs in the day-ahead market, were paid $6.2 million in loss credits in the balancing energy market and were paid $0.9 million in total loss credits. In the first six months of 2019, up to congestion paid $22.7 million in loss costs in the day-ahead market, were paid $29.3 million in loss credits in the balancing energy market and received $6.6 million in total loss credits.

Table 11-34 Total PJM loss costs by transaction type by market (Dollars (Millions)): January through June, 2019

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($2.2)	$0.0	$0.0	($2.2)	$2.8	$0.0	$0.0	$2.8	$0.0	$0.6
Demand	($2.8)	$0.0	$0.0	($2.8)	$2.6	$0.0	$0.0	$2.6	$0.0	($0.2)
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	($0.3)	($0.3)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.3)
Export	($9.4)	$0.0	$0.0	($9.3)	($4.8)	$0.0	$0.4	($4.5)	$0.0	($13.8)
Generation	$0.0	($335.2)	$0.0	$335.2	$0.0	($4.4)	$0.0	$4.4	$0.0	$339.6
Import	$0.0	($1.1)	$0.0	$1.1	$0.0	($3.7)	($0.1)	$3.6	$0.0	$4.8
INC	$0.0	($5.4)	$0.0	$5.4	$0.0	$6.2	$0.0	($6.2)	$0.0	($0.9)
Internal Bilateral	($8.6)	($8.5)	$0.1	$0.0	($0.5)	($0.5)	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$22.7	$22.7	$0.0	$0.0	($29.3)	($29.3)	$0.0	($6.6)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($23.0)	($350.2)	$22.6	$349.7	$0.1	($2.4)	($29.2)	($26.6)	$0.0	$323.1

Table 11-35 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 Only	$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)	($5.0)	$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

Monthly Marginal Loss Costs

Table 11-36 shows a monthly summary of marginal loss costs by market type for January 2018 through June 2019.

Table 11-36 Monthly marginal loss costs by market (Millions): January 2018 through June 2019

	Marginal Loss Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$227.1	($4.3)	$0.0	$222.8	$92.3	($5.8)	$0.0	$86.5
Feb	$52.7	($3.2)	$0.0	$49.5	$57.2	($3.3)	$0.0	$53.9
Mar	$67.2	$0.0	$0.0	$67.2	$68.5	($7.0)	$0.0	$61.6
Apr	$56.3	($0.9)	$0.0	$55.4	$42.7	($3.9)	$0.0	$38.8
May	$64.5	($1.1)	$0.0	$63.4	$45.2	($3.9)	($0.0)	$41.3
Jun	$66.5	($3.4)	($0.0)	$63.2	$43.9	($2.8)	($0.0)	$41.1
Jul	$85.7	($3.5)	$0.0	$82.2				
Aug	$87.7	($4.6)	$0.0	$83.1				
Sep	$73.2	($2.9)	$0.0	$70.2				
Oct	$65.0	($3.0)	($0.0)	$62.1				
Nov	$77.6	($5.4)	($0.0)	$72.2				
Dec	$73.7	($4.8)	($0.0)	$68.9				
Total	$997.2	($37.1)	$0.0	$960.1	$349.7	($26.6)	$0.0	$323.1

Figure 11-8 shows PJM monthly marginal loss costs for January 2008 through June 2019.

Figure 11-8 PJM monthly marginal loss costs (Dollars (Millions)): January 2008 through June 2019

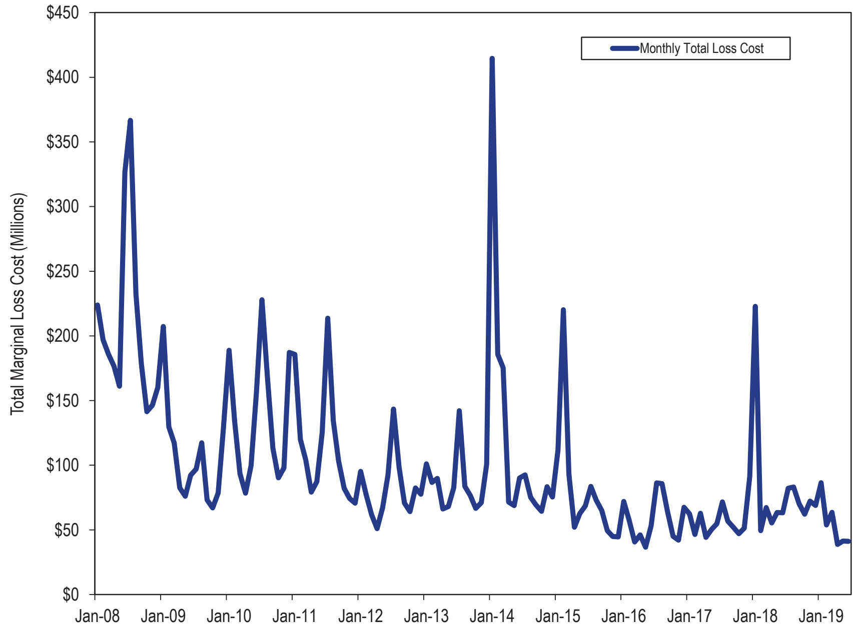


Table 11-37 shows the monthly total loss costs for each virtual transaction type in the first six months of 2019 and year of 2018.

Table 11-37 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 2019

Marginal Loss Costs (Millions)											
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$0.2	($0.5)	($0.3)	$2.1	($2.4)	($0.2)	$6.6	($8.5)	($1.9)	($2.5)
	Feb	($0.2)	$0.0	($0.1)	$0.5	($0.5)	($0.1)	$2.5	($3.9)	($1.4)	($1.6)
	Mar	($0.0)	$0.2	$0.2	$1.3	($1.4)	($0.1)	$1.2	($1.5)	($0.3)	($0.2)
	Apr	($0.1)	$0.2	$0.1	$1.1	($1.2)	($0.2)	$1.5	($2.1)	($0.6)	($0.7)
	May	($0.5)	$0.5	$0.0	$1.1	($1.2)	($0.1)	$2.2	($2.8)	($0.6)	($0.7)
	Jun	($0.3)	$0.5	$0.2	$1.1	($1.1)	($0.0)	$3.0	($3.5)	($0.4)	($0.3)
	Jul	($0.1)	$0.2	$0.1	$0.8	($0.8)	($0.0)	$3.8	($4.4)	($0.7)	($0.6)
	Aug	($0.2)	$0.1	($0.1)	$1.0	($1.1)	($0.1)	$4.4	($5.8)	($1.3)	($1.5)
	Sep	($0.3)	$0.5	$0.3	$1.2	($1.4)	($0.1)	$3.8	($4.6)	($0.7)	($0.6)
	Oct	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.1)	$3.3	($4.0)	($0.7)	($0.6)
	Nov	($0.0)	$0.2	$0.1	$1.5	($1.6)	($0.1)	$5.4	($6.5)	($1.1)	($1.1)
	Dec	($0.2)	$0.4	$0.1	$0.7	($0.9)	($0.2)	$4.6	($5.8)	($1.3)	($1.3)
	Total	($2.0)	$2.7	$0.7	$13.6	($15.0)	($1.4)	$42.3	($53.3)	($11.0)	($11.8)
2019	Jan	($0.2)	$0.4	$0.2	$1.1	($1.4)	($0.3)	$5.4	($6.5)	($1.1)	($1.2)
	Feb	($0.4)	$0.3	($0.1)	$0.8	($1.0)	($0.3)	$3.1	($4.4)	($1.3)	($1.6)
	Mar	($0.1)	$0.2	$0.0	$1.3	($1.4)	($0.1)	$5.9	($6.8)	($0.9)	($1.0)
	Apr	($0.3)	$0.3	$0.0	$0.7	($0.8)	($0.1)	$3.3	($4.1)	($0.8)	($0.9)
	May	($0.7)	$0.9	$0.2	$0.9	($0.8)	$0.0	$3.2	($4.2)	($0.9)	($0.7)
	Jun	($0.5)	$0.7	$0.2	$0.6	($0.7)	($0.1)	$1.8	($3.4)	($1.6)	($1.5)
	Total	($2.2)	$2.8	$0.6	$5.4	($6.2)	($0.9)	$22.7	($29.3)	($6.6)	($6.9)

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 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 11-38 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 2019. The total marginal loss surplus decreased $71.4 million in the first six months of 2019 from the first six months of 2018.

Table 11-38 Marginal loss surplus (Dollars (Millions)): January through June, 2008 through 2019[31]

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	$0.0	$3.9	$0.1	$157.9
2014	($677.2)	$1,006.2	($0.3)	$3.7	($0.1)	$325.1
2015	($397.6)	$608.3	$0.0	$1.3	($0.1)	$209.5
2016	($204.2)	$305.8	$0.0	$0.3	($0.1)	$101.4
2017	($222.2)	$320.6	($0.0)	$1.3	($0.0)	$97.2
2018	($345.2)	$521.4	($0.0)	$0.7	($0.0)	$175.6
2019	($218.9)	$323.1	$0.0	$0.0	$0.0	$104.2

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, 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 2019 was -$218.9 million, which was comprised of load energy payments of $15,347.6 million, generation energy credits of $15,567.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of $1.3 million. The monthly energy costs for the first six months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-39 shows total energy component costs and total PJM billing, for January through June, 2008 through 2019. The total energy component costs are net energy costs.

Table 11-39 Total PJM energy component costs (Dollars (Millions)): January through June, 2008 through 2019[32]

(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%)
2019	($219)	(36.6%)	$20,070	(1.1%)

Energy costs for January through June, 2008 through 2019 are shown in Table 11-40 and Table 11-41. Table 11-40 shows PJM energy costs by accounting category and Table 11-41 shows PJM energy costs by market category.

31 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

32 The energy costs include net inadvertent charges.

Table 11-40 Total PJM energy costs by accounting category (Dollars (Millions)): January through June, 2008 through 2019

	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	$23,079.7	$23,429.7	$0.0	$4.9	($345.2)
2019	$15,347.6	$15,567.8	$0.0	$1.3	($218.9)

Table 11-41 Total PJM energy costs by market category (Dollars (Millions)): January through June, 2008 through 2019

	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)	($46.7)	($77.1)	$0.0	$30.3	$4.9	($345.2)
2019	$15,552.6	$15,820.6	$0.0	($268.0)	($205.0)	($252.7)	$0.0	$47.7	$1.3	($218.9)

Table 11-42 and Table 11-43 show the total energy costs for each transaction type in the first six months of 2019 and 2018. In the first six months of 2019, generation was paid $11,097.2 million and demand paid $10,476.8 million in net energy payment. 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.

Table 11-42 Total PJM energy costs by transaction type by market (Dollars (Millions)): January through June, 2019

	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	$462.9	$0.0	$0.0	$462.9	($455.9)	$0.0	$0.0	($455.9)	$7.0
Demand	$10,468.1	$0.0	$0.0	$10,468.1	$8.7	$0.0	$0.0	$8.7	$10,476.8
Demand Response	($0.4)	$0.0	$0.0	($0.4)	$0.4	$0.0	$0.0	$0.4	($0.0)
Export	$339.7	$0.0	$0.0	$339.7	$217.8	$0.0	$0.0	$217.8	$557.5
Generation	$0.0	$11,138.7	$0.0	($11,138.7)	$0.0	($41.5)	$0.0	$41.5	($11,097.2)
Import	$0.0	$46.6	$0.0	($46.6)	$0.0	$110.2	$0.0	($110.2)	($156.8)
INC	$0.0	$353.0	$0.0	($353.0)	$0.0	($345.4)	$0.0	$345.4	($7.6)
Internal Bilateral	$4,282.2	$4,282.2	$0.0	($0.0)	$11.3	$11.3	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$12.7	$0.0	($12.7)	($12.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$12.7	$0.0	$0.0	$12.7	$12.7
Total	$15,552.6	$15,820.6	$0.0	($268.0)	($205.0)	($252.7)	$0.0	$47.7	($220.3)

Table 11-43 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)	$9.6	$9.6	$0.0	$0.0	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$4.0	$0.0	($4.0)	($4.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$4.0	$0.0	$0.0	$4.0	$4.0
Total	$23,126.4	$23,506.8	$0.0	($380.4)	($46.7)	($77.0)	$0.0	$30.3	($350.0)

Monthly Energy Costs

Table 11-44 shows a monthly summary of energy costs by market type for January 2018 through June 2019. Marginal total energy costs in the first six months of 2019 increased from the first six months of 2018. Monthly total energy costs in the first six months of 2019 ranged from -$59.3 million in January to -$25.7 million in April.

Table 11-44 Monthly energy costs by market type (Dollars (Millions)): January 2018 through June 2019

	Energy Costs (Millions)							
	2018				2019			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($160.3)	$4.9	$4.6	($150.9)	($69.5)	$9.8	$0.4	($59.3)
Feb	($41.2)	$7.4	$0.1	($33.6)	($42.8)	$6.9	$0.5	($35.4)
Mar	($45.0)	$2.9	$0.1	($42.1)	($54.2)	$12.3	$0.2	($41.6)
Apr	($40.4)	$2.6	($0.0)	($37.8)	($34.2)	$8.1	$0.4	($25.7)
May	($46.5)	$5.4	$0.3	($40.8)	($34.5)	$6.6	($0.1)	($28.0)
Jun	($47.0)	$7.2	($0.1)	($39.9)	($32.8)	$4.2	($0.2)	($28.8)
Jul	($59.6)	$5.7	$0.5	($53.5)				
Aug	($60.7)	$5.7	$0.3	($54.6)				
Sep	($50.8)	$5.3	($0.0)	($45.4)				
Oct	($47.2)	$4.5	($0.6)	($43.2)				
Nov	($57.2)	$9.8	($0.2)	($47.6)				
Dec	($55.2)	$8.4	($0.4)	($47.2)				
Total	($711.0)	$69.7	$4.6	($636.7)	($268.0)	$47.7	$1.3	($218.9)

Figure 11-9 shows PJM monthly energy costs for January 2008 through June 2019.

Figure 11-9 PJM monthly energy costs (Millions): January 2008 through June 2019

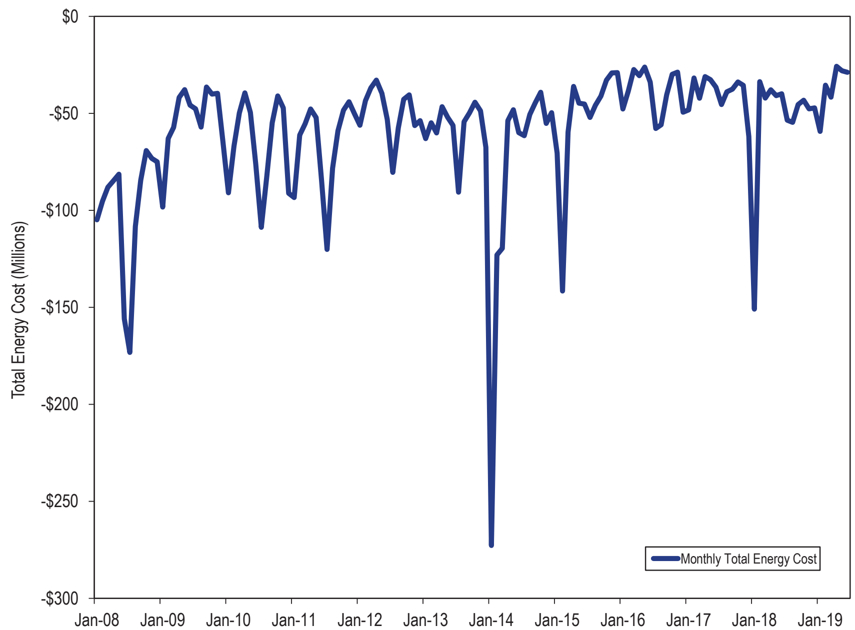


Table 11-45 shows the monthly total energy costs for each virtual transaction type in the first six months of 2019 and year of 2018. In the first six months of 2019, DECs paid $462.9 million in energy costs in the day-ahead market, were paid $455.9 million in energy credits in the balancing energy market and paid $7.0 million in total energy costs. In the first six months of 2019, INCs were paid $353.0 million in energy credits in the day-ahead market, paid $345.4 million in energy costs in the balancing market and were paid $7.6 million in total energy credits. 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 total energy credits. 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 cost in the balancing energy market and paid $3.5 million in total energy costs.

Table 11-45 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): January 2018 through June 2019

Energy Costs (Millions)									
		DEC			INC				
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2018	Jan	$172.4	($183.2)	($10.8)	($136.9)	$138.3	$1.4	($9.4)
	Feb	$47.3	($45.1)	$2.2	($46.3)	$44.2	($2.1)	$0.1
	Mar	$65.6	($67.2)	($1.6)	($66.0)	$66.5	$0.4	($1.2)
	Apr	$66.2	($67.6)	($1.4)	($76.3)	$76.8	$0.5	($0.9)
	May	$86.7	($94.7)	($8.0)	($73.7)	$78.0	$4.3	($3.7)
	Jun	$77.1	($74.5)	$2.6	($53.8)	$52.7	($1.0)	$1.6
	Jul	$76.5	($71.6)	$4.9	($48.7)	$43.9	($4.7)	$0.2
	Aug	$75.8	($75.3)	$0.6	($57.4)	$57.4	($0.0)	$0.6
	Sep	$94.5	($98.5)	($4.0)	($65.6)	$67.4	$1.8	($2.2)
	Oct	$86.7	($82.4)	$4.3	($85.8)	$82.1	($3.7)	$0.6
	Nov	$83.1	($80.9)	$2.2	($88.9)	$86.6	($2.3)	($0.2)
	Dec	$79.0	($78.4)	$0.6	($60.8)	$59.2	($1.6)	($1.0)
	Total	$1,010.9	($1,019.5)	($8.6)	($860.1)	$853.0	($7.1)	($15.7)
2019	Jan	$104.4	($97.7)	$6.7	($71.7)	$67.1	($4.6)	$2.1
	Feb	$64.0	($66.8)	($2.8)	($52.5)	$54.0	$1.6	($1.2)
	Mar	$76.6	($77.4)	($0.8)	($66.7)	$65.4	($1.2)	($2.0)
	Apr	$60.3	($59.7)	$0.6	($59.0)	$58.5	($0.5)	$0.1
	May	$81.9	($79.1)	$2.9	($56.1)	$53.9	($2.2)	$0.6
	Jun	$75.8	($75.3)	$0.4	($47.1)	$46.5	($0.6)	($0.2)
	Total	$462.9	($455.9)	$7.0	($353.0)	$345.4	($7.6)	($0.6)