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] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into 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 the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as 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. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution. CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) 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. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as 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 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.[4] 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 single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2022 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
4 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.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system 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.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the elected reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local 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. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day ahead and real time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making them negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges.

5 The total congestion and marginal losses for 2022 were calculated as of January 10, 2023, and are subject to change, based on continued PJM billing updates.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,506.0 million or 151.3 percent, from $995.3 million in 2021 to $2,501.3 million in 2022.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,799.1 million or 146.7 percent, from $1,226.2 million in 2021 to $3,025.2 million in 2022.
- **Balancing Congestion.** Negative balancing congestion costs increased by $293.0 million, from -$230.9 million in 2021 to -$523.9 million in 2022. Negative balancing explicit charges increased by $254.8 million, from -$100.7 million in 2021 to -$355.4 million in 2022.
- **Real-Time Congestion.** Real-time congestion costs increased by $2,423.6 million, from $1,456.0 million in 2021 to $3,879.7 million in 2022.
- **Monthly Congestion.** Monthly total congestion costs in 2022 ranged from $74.5 million in March to $354.2 million in May.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Nottingham Series Reactor, the Brambleton - Evergreen Mills Line, the Cumberland - Juniata Line, the AP South Interface and the Beaumeade Circuit Breaker.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 2022. The number of congestion event hours in the day-ahead energy market was about two and half times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency increased by 29.0 percent from 56,617 congestion event hours in 2021 to 73,031 congestion event hours in 2022.

  Real-time congestion frequency increased by 20.3 percent from 23,068 congestion event hours in 2021 to 27,744 congestion event hours in 2022.
- **Congested Facilities.** Day-ahead, congestion event hours increased on all types of facilities.

  The Nottingham Series Reactor was the largest contributor to congestion costs in 2022. With $283.4 million in total congestion costs, it accounted for 11.3 percent of the total PJM congestion costs in 2022.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in 2021 or 2022.
- **Zonal Congestion.** DOM had the highest zonal congestion costs among all control zones in 2022. DOM had $440.6 million in zonal congestion costs, comprised of $541.2 million in day-ahead congestion costs and -$100.6 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $963.2 million or 100.9 percent, from $954.8 million in 2021 to $1,918.0 million in 2022. The loss MWh in PJM increased by 1,148.0 GWh or 7.5 percent, from 15,127.0 GWh in 2021 to 16,419.0 GWh in 2022. The loss component of real-time LMP in 2022 was $0.06, compared to $0.02 in 2021.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $1,064.4million or 107.7 percent, from $987.9 million in 2021 to $2,052.3 million in 2022.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs increased by $101.2 million or 305.8 percent, from -$33.1 million in 2021 to -$134.2 million in 2022.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased by $303.6 million or 91.9 percent, from $330.4 million in 2021, to $633.9 million in 2022.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2022 ranged from $85.7 million in March to $257.4 million in August.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs decreased by $658.9 million or 105.7 percent, from -$623.2 million in 2021 to -$1,282.1 million in 2022.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs decreased by $807.9 million or 119.1 percent, from -$678.2 million in 2021 to -$1,486.2 million in 2022.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $172.7 million or 330.4 percent, from $52.3 million in 2021 to $225.0 million in 2022.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in 2022 ranged from -$168.6 million in August to -$60.0 million in March.

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined 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 costs in 2022 were the highest for any comparable period since 2008 due to higher fuel prices, especially higher gas and coal prices; cold weather in January; Winter Storm Elliott (Elliott) in December; higher frequency of transmission constraint violations in the day-ahead market; and increased load in the Data Center Alley area of Northern Virginia.

Monthly total congestion costs ranged from $74.5 million in March to $354.2 million in May in 2022.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self scheduled FTRs in the first seven months of the 2022/2023 planning period was 61.8 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first four months of the 2022/2023 planning period, using the rules effective for each planning period, was 67.2 percent. Load has received $4.0 billion less than load should have received from the 2011/2012 planning period through the first seven months of the 2022/2023 planning period.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day ahead and real time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive congestion. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day ahead and real time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day ahead and real time market, is that the apparent location of the interface or parent constraint can move intra day relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic to force inflexible units to be on the margin in both real time and day ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used 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's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[6] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints 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 result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results 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.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is 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 charges.

Elliott

Figure 11-1 shows hourly day-ahead, balancing, and total congestion costs on December 23 through 26, 2022. The total congestion costs on those four days accounted for 51.8 percent of total congestion costs in December 2022 ($158.6 million out of $306.4 million). The balancing congestion costs were positive and very high in the HE 1300 (EPT), HE 1800 (EPT) through HE 2000 (EPT) on December 23, 2022, and HE 0700 (EPT) through HE 0900 (EPT) on December 24, 2022. The balancing congestion costs were positive in every hour on December 25, 2022. The total congestion costs were highest in HE 1900 (EPT) on December 23, 2022, due to high positive balancing congestion costs and were second highest in HE 0700 (EPT) on December 24, 2022, due to high day-ahead congestion costs and high positive balancing congestion costs.

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

Figure 11-1 Hourly congestion costs by market (Dollars): Dec 23 through 26, 2022

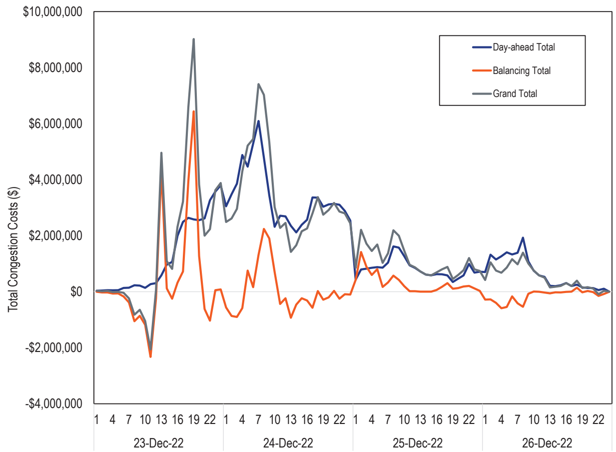


Figure 11-2 shows the hourly total congestion for the top five constraints affecting total congestion costs on December 23, 2022.

The AP South Interface had the largest total positive congestion costs on December 23, 2022, but was only binding in the day-ahead market. The AEP – DOM Interface had the largest total negative congestion costs on December 23, 2022. The majority of negative balancing congestion costs of the AEP – DOM Interface on December 23, 2022, resulted from changes in generation output between the day-ahead and real-time markets on both the constrained and unconstrained sides of the AEP – DOM Interface. On the constrained side of the AEP – DOM Interface, the real-time generation was greater than the DA generation because some generation units in the DOM Zone were not scheduled to run in the day-ahead market, but ran in the real-time market to meet the load that was greater than load in the day-ahead market. This scheduling of additional generation resources in real time caused the AEP – DOM interface related generation credits on the constrained side to be higher in real-time than in the day-ahead market. This resulted in negative balancing charges. On the unconstrained side of the AEP – DOM Interface, many units scheduled to run in the day-ahead market failed to start in real time, due to cold weather related outages, which required replacement MW to be provided by relatively expensive resources in real time. This also resulted in negative balancing charges.

Figure 11-2 Top five constraints affecting total congestion costs, by hour: Dec 23, 2022

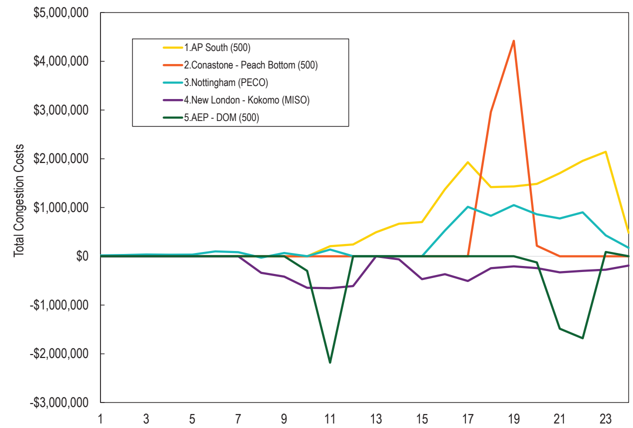


Figure 11-3 shows the hourly total congestion of the top five constraints on December 24, 2022. The AEP – DOM Interface had the largest total negative congestion costs. The majority of negative balancing congestion costs for the AEP – DOM interface were the result of DECs' and UTCs' net credits.

Figure 11-3 Top five constraints affecting total congestion costs, by hour: Dec 24, 2022

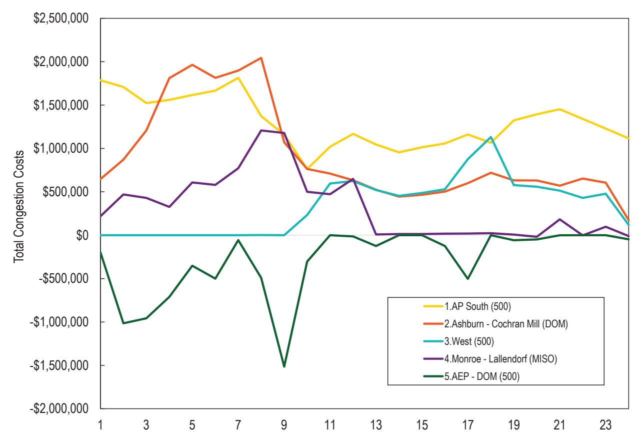


Figure 11-4 shows the hourly total congestion of the top five constraints affecting total congestion costs on December 25, 2022. Two of the top five constraints were M2M flowgates between MISO and PJM. The Maroa E - Goose Creek flowgate, a M2M flowgate between MISO and PJM, had the largest total congestion costs. The Elimsport – Sunbury Line and the 5004/5005 Interface were only binding in the day-ahead market and the AP South was only binding in the real-time market.

Figure 11-4 Top five constraints affecting total congestion costs, by hour: Dec 25, 2022

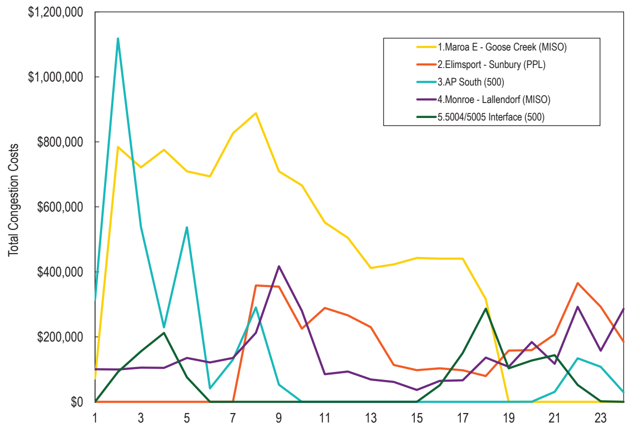
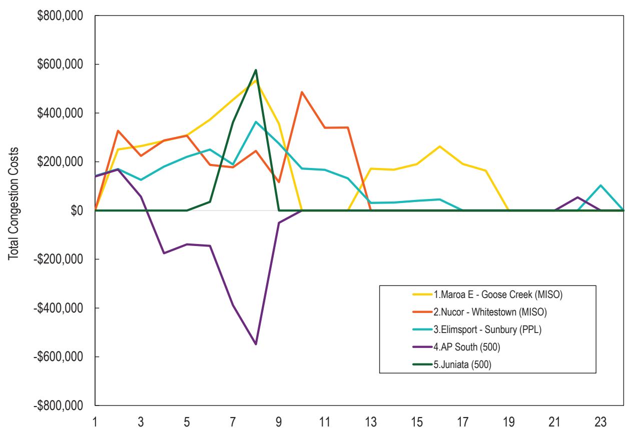


Figure 11-5 shows the hourly total congestion of the top five constraints affecting total congestion costs on December 26, 2022, by hour. One of the top five constraints was the AP South Interface, two were M2M flowgates between MISO and PJM and two were located in the PPL Zone. The AP South Interface had the largest negative total congestion costs on December 26, 2022, due to large negative balancing congestion costs resulting from net credits paid to UTCs.

Figure 11-5 Top five constraints affecting total congestion costs, by hour: Dec 26, 2022



Locational Marginal Price (LMP) Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some price effects of binding constraint may be 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 system 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. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow 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.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for 2008 through 2022.[9]

The real-time load-weighted average LMP increased by $40.36 or 101.4 percent from $39.78 in 2021 to $80.14 in 2022. The real-time load-weighted average congestion component was $0.10 in 2022, compared to $0.04 in 2021. The real-time load-weighted, average loss component in 2022 was $0.06, compared to $0.02 in 2021. The real-time load-weighted average system energy component increased by $40.26 or 101.3 percent from $39.72 in 2021 to $79.98 in 2022. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero, although these components are not fully accurate.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): 2008 through 2022[10]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02
2019	$27.32	$27.28	$0.02	$0.02
2020	$21.77	$21.73	$0.02	$0.01
2021	$39.78	$39.72	$0.04	$0.02
2022	$80.14	$79.98	$0.10	$0.06

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for 2008 through 2022. The day-ahead load-weighted average LMP increased by $36.07, or 91.6 percent, from $39.37 in 2021 to $75.44 in 2022. The day-ahead load-weighted average congestion component increased by $0.16 from $0.10 in 2021 to $0.26 in 2022. The day-ahead load-weighted average loss component was $0.16 in 2022, compared to $0.02 in 2021. The day-ahead load-weighted average energy component increased by $35.76, or 91.1 percent, from $39.25 in 2021 to $75.01 in 2022. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): 2008 through 2022

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)
2019	$27.23	$27.17	$0.08	($0.01)
2020	$21.40	$21.34	$0.07	($0.00)
2021	$39.37	$39.25	$0.10	$0.02
2022	$75.44	$75.01	$0.26	$0.16

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

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

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2021 and 2022

	2021		2022	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$25.96	$21.31	$69.75	$38.74
Feb	$45.23	$23.19	$47.17	$38.47
Mar	$26.57	$19.67	$43.43	$47.62
Apr	$26.93	$21.82	$63.91	$0.00
May	$30.74	$22.46	$84.99	$58.69
Jun	$35.33	$26.34	$105.87	$54.44
Jul	$42.25	$28.29	$98.97	$59.33
Aug	$53.08	$30.84	$125.07	$72.12
Sep	$52.26	$34.37	$80.41	$63.94
Oct	$59.05	$37.60	$56.22	$42.28
Nov	$62.98	$65.82	$53.58	$48.87
Dec	$39.32	$31.41	$155.97	$49.83
Avg	$41.73	$27.52	$82.56	$57.72

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for 2021 and 2022. In 2022, DOM had the highest real-time congestion component of all control zones, $16.57, and PECO had the lowest real-time congestion component, -$9.11.

Table 11-4 Zonal real-time load-weighted average LMP components (Dollars per MWh): 2021 and 2022

	2021				2022			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$34.13	$40.20	($6.35)	$0.28	$74.27	$82.01	($9.07)	$1.33
AEP	$40.31	$39.50	$0.83	($0.02)	$77.54	$79.32	($1.11)	($0.67)
APS	$40.44	$39.52	$0.94	($0.03)	$79.01	$79.61	($0.60)	$0.00
ATSI	$39.47	$39.66	($0.36)	$0.17	$74.96	$78.32	($3.02)	($0.34)
BGE	$45.77	$39.92	$4.79	$1.07	$95.44	$81.87	$10.24	$3.33
COMED	$37.00	$39.81	($1.69)	($1.13)	$66.25	$78.91	($9.02)	($3.63)
DAY	$42.92	$39.89	$1.51	$1.51	$80.43	$79.74	($1.06)	$1.74
DOM	$44.67	$39.78	$4.34	$0.55	$99.52	$81.08	$16.57	$1.88
DPL	$40.24	$39.88	($0.31)	$0.67	$83.32	$82.21	($1.48)	$2.58
DUKE	$41.49	$39.84	$1.61	$0.04	$79.54	$80.61	($0.37)	($0.70)
DUQ	$39.17	$39.70	($0.04)	($0.49)	$74.76	$79.27	($3.09)	($1.42)
EKPC	$41.20	$39.93	$1.35	($0.07)	$83.16	$83.66	$0.05	($0.56)
JCPLC	$34.52	$40.27	($5.96)	$0.21	$76.02	$82.22	($7.28)	$1.07
MEC	$39.97	$39.69	$0.44	($0.16)	$82.20	$79.14	$2.43	$0.63
OVEC	$37.98	$38.08	$0.74	($0.84)	$71.39	$74.99	($1.39)	($2.21)
PE	$37.73	$39.39	($1.38)	($0.27)	$73.26	$77.37	($3.65)	($0.46)
PECO	$33.55	$39.73	($5.92)	($0.25)	$71.67	$80.53	($9.11)	$0.25
PEPCO	$44.62	$39.95	$3.96	$0.72	$91.68	$81.50	$7.61	$2.56
PPL	$35.92	$39.47	($3.00)	($0.55)	$75.74	$78.97	($2.95)	($0.28)
PSEG	$35.78	$39.81	($4.17)	$0.14	$74.74	$79.97	($6.06)	$0.83
REC	$38.80	$40.28	($1.71)	$0.23	$77.95	$81.82	($4.56)	$0.69
PJM	$39.78	$39.72	$0.04	$0.02	$80.14	$79.98	$0.10	$0.06

The day-ahead components of LMP for each control zone are presented in Table 11-5 for 2021 and 2022. In 2022, DOM had the highest day-ahead congestion component of all control zones, $13.33, and PECO had the lowest day-ahead congestion component, -$9.32.

Table 11-5 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): 2021 and 2022

	2021				2022			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$33.90	$39.67	($5.86)	$0.10	$69.26	$76.98	($9.15)	$1.43
AEP	$39.93	$39.11	$0.83	($0.01)	$73.93	$74.51	$0.16	($0.74)
APS	$40.05	$39.03	$1.01	$0.00	$74.23	$73.68	$0.55	$0.01
ATSI	$39.56	$39.02	$0.30	$0.23	$72.97	$74.23	($1.04)	($0.22)
BGE	$45.51	$39.46	$5.00	$1.05	$89.02	$76.19	$9.60	$3.23
COMED	$36.49	$39.16	($1.71)	($0.96)	$64.68	$74.55	($7.01)	($2.86)
DAY	$42.69	$39.45	$1.58	$1.67	$76.99	$74.84	$0.54	$1.62
DOM	$43.66	$39.39	$3.80	$0.47	$90.84	$75.80	$13.33	$1.71
DPL	$39.43	$39.62	($0.87)	$0.67	$75.88	$76.69	($3.60)	$2.79
DUKE	$41.42	$39.22	$1.98	$0.22	$76.45	$75.62	$1.49	($0.66)
DUQ	$39.21	$39.20	$0.47	($0.46)	$72.21	$74.85	($1.18)	($1.46)
EKPC	$40.90	$39.76	$1.45	($0.31)	$75.60	$76.00	$1.15	($1.56)
JCPLC	$34.52	$39.62	($5.15)	$0.05	$70.21	$77.08	($8.07)	$1.20
MEC	$39.66	$39.33	$0.61	($0.28)	$78.62	$74.50	$3.18	$0.93
OVEC	$40.95	$41.44	$0.34	($0.83)	$67.55	$67.42	$1.50	($1.36)
PE	$38.93	$39.44	($0.51)	($0.01)	$72.00	$73.96	($2.15)	$0.18
PECO	$33.24	$39.15	($5.50)	($0.41)	$67.03	$75.89	($9.32)	$0.45
PEPCO	$44.05	$39.64	$3.59	$0.82	$86.23	$76.47	$7.06	$2.70
PPL	$35.73	$38.91	($2.42)	($0.77)	$71.72	$74.13	($2.32)	($0.08)
PSEG	$34.91	$39.28	($4.40)	$0.04	$69.74	$75.32	($6.75)	$1.17
REC	$38.00	$39.62	($1.77)	$0.15	$73.49	$76.27	($3.94)	$1.15
PJM	$39.37	$39.25	$0.10	$0.02	$75.44	$75.01	$0.26	$0.16

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for 2021 and 2022.[11]

Table 11-6 Hub real-time average LMP components (Dollars per MWh): 2021 and 2022

	2021				2022			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$37.44	$38.12	$0.36	($1.04)	$72.69	$76.21	($0.90)	($2.62)
AEP-DAY Hub	$38.63	$38.12	$0.63	($0.12)	$73.82	$76.21	($1.18)	($1.21)
ATSI Gen Hub	$37.20	$38.12	($0.41)	($0.51)	$71.94	$76.21	($1.86)	($2.41)
Chicago Gen Hub	$34.31	$38.12	($2.25)	($1.57)	$59.03	$76.21	($11.49)	($5.70)
Chicago Hub	$35.21	$38.12	($1.90)	($1.02)	$60.58	$76.21	($11.03)	($4.60)
Dominion Hub	$41.47	$38.12	$3.17	$0.18	$83.78	$76.21	$6.10	$1.48
Eastern Hub	$37.20	$38.12	($1.45)	$0.52	$74.04	$76.21	($4.00)	$1.82
N Illinois Hub	$34.96	$38.12	($1.94)	($1.23)	$59.99	$76.21	($11.20)	($5.02)
New Jersey Hub	$33.20	$38.12	($4.98)	$0.06	$69.21	$76.21	($7.34)	$0.34
Ohio Hub	$38.60	$38.12	$0.54	($0.06)	$73.32	$76.21	($1.48)	($1.41)
West Interface Hub	$38.61	$38.12	$0.94	($0.46)	$76.93	$76.21	$1.85	($1.13)
Western Hub	$38.88	$38.12	$0.89	($0.14)	$77.53	$76.21	$0.84	$0.48

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

The day-ahead components of LMP for each hub are presented in Table 11-7 for 2021 and 2022.

Table 11-7 Hub day-ahead average LMP components (Dollars per MWh): 2021 and 2022

	2021				2022			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$37.39	$37.69	$0.66	($0.96)	$68.08	$70.44	($0.01)	($2.35)
AEP-DAY Hub	$38.35	$37.69	$0.71	($0.05)	$69.41	$70.44	($0.14)	($0.88)
ATSI Gen Hub	$37.62	$37.69	$0.26	($0.33)	$68.07	$70.44	($1.01)	($1.35)
Chicago Gen Hub	$34.22	$37.69	($2.10)	($1.37)	$59.45	$70.44	($7.44)	($3.55)
Chicago Hub	$34.96	$37.69	($1.89)	($0.85)	$60.65	$70.44	($7.17)	($2.61)
Dominion Hub	$40.27	$37.69	$2.51	$0.07	$76.50	$70.44	$5.51	$0.55
Eastern Hub	$36.28	$37.69	($1.94)	$0.52	$67.50	$70.44	($5.09)	$2.15
N Illinois Hub	$34.71	$37.69	($1.91)	($1.07)	$60.17	$70.44	($7.23)	($3.04)
New Jersey Hub	$32.85	$37.69	($4.78)	($0.06)	$64.31	$70.44	($7.03)	$0.90
Ohio Hub	$38.32	$37.69	$0.63	($0.00)	$69.30	$70.44	($0.29)	($0.85)
West Interface Hub	$38.50	$37.69	$1.19	($0.38)	$71.13	$70.44	$1.51	($0.82)
Western Hub	$38.92	$37.69	$1.22	$0.00	$73.09	$70.44	$1.84	$0.81

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[12] 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.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP 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.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[13] Day-ahead

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

13 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

implicit injection 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.

- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges 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 implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection 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 implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are 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 CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion accounting calculation equations are in Table 11-8.

Table 11-8 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

14 PJM Operating Agreement Schedule 1 §3.7.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. 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 CLMP 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 CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay 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 congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

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 from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

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 calculation is designed to include no congestion or loss components, but it may include congestion. The load weighted 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 CLMP charges is logically zero and the small reported 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. Due to transmission constraints, 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 bus CLMPs is negative. This means that total generation CLMP credits are negative.

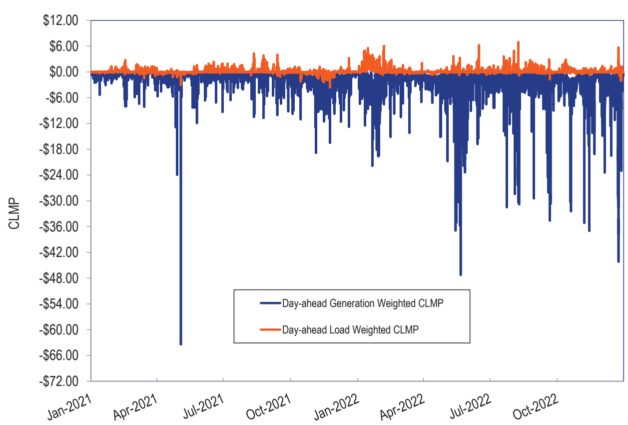
Figure 11-6 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-6 shows that in 2021 and 2022, day-ahead generation weighted CLMPs were generally negative and day-ahead load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than

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

the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-11 and Table 11-12). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

The day-ahead, generation weighted CLMPs were significantly negative for two hours on May 4, 2021, due to high shadow prices of two constraints caused by a transmission outage in the DOM Zone. The day-ahead generation weighted CLMPs were significantly negative for three hours on May 22, 2022 due to transmission constraint violations in HE 1400, HE 1700 and HE 1800. The day-ahead generation weighted CLMPs were significantly negative for two hours on September 21, 2022, due to transmission constraint violations in HE 1600 and HE 1700 on the Brambleton - Evergreen Mills Line.

Figure 11-6 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: 2021 and 2022



Total Congestion

Total congestion costs in PJM in 2022 were $2,501.3 million, comprised of implicit withdrawal charges of $1,228.8 million, minus implicit injection credits of -$1,481.1 million, and plus explicit charges of -$208.6 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-9 shows total congestion for 2008 through 2022. Total congestion costs in Table 11-9 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16] [17]

Table 11-9 Total congestion costs (Dollars (Millions)): 2008 through 2022[18]

	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,300	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,770	4.1%
2011	$999	(29.8%)	$35,890	2.8%
2012	$529	(47.0%)	$29,180	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%
2019	$583	(55.5%)	$41,680	1.4%
2020	$529	(9.4%)	$36,280	1.5%
2021	$995	88.2%	$54,130	1.8%
2022	$2,501	151.3%	$86,220	2.9%

CLMP charges and credits are not congestion. CLMP charges and credits reflect 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 CLMP credits and charges at the close 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 2008 through 2022.

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.
17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.
18 In Table 11-9, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-10 Total CLMP credits and charges by accounting category (Dollars (Millions)): 2008 through 2022

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9
2019	$246.0	($412.3)	$55.7	$714.0	$3.7	$51.1	($83.3)	($130.7)	$0.0	$583.3
2020	$193.2	($401.7)	$67.5	$662.5	($14.7)	$41.5	($77.6)	($133.8)	$0.0	$528.7
2021	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$0.0	$995.3
2022	$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	($0.0)	$2,501.3

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market, that make up a market day.

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 CLMP credits and charges at the close of each market 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.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay 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 congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-11 and Table 11-12 show the total CLMP charges and credits for each transaction type in 2022 and 2021. Table 11-11 shows that in 2022 DECs paid $15.1 million in CLMP charges in the day-ahead market, were paid $66.9 million in CLMP credits in the balancing energy market, resulting in a net payment of $51.8 million in total CLMP credits. In 2022, INCs paid $101.6 million in CLMP charges in the day-ahead market, were paid $170.3 million in CLMP credits in the balancing energy market resulting in a net payment of $68.7 million in total CLMP credits. In 2022, up to congestion (UTCs) paid $144.1 million in CLMP charges in the day-ahead market, were paid $357.3 million in CLMP credits in the balancing market resulting in a total payment of $213.2 million in total CLMP credits.

Table 11-11 Total CLMP credits and charges by transaction type (Dollars (Millions)): 2022

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$15.1	$0.0	$0.0	$15.1	($66.9)	$0.0	$0.0	($66.9)	$0.0	($51.8)
Demand	$197.6	$0.0	$0.0	$197.6	$129.9	$0.0	$0.0	$129.9	$0.0	$327.5
Demand Response	$0.3	$0.0	$0.0	$0.3	($0.5)	$0.0	$0.0	($0.5)	$0.0	($0.2)
Explicit Congestion Only	$0.0	$0.0	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.4)
Export	($74.2)	$0.0	($0.9)	($75.1)	($16.6)	$0.0	$3.6	($13.0)	$0.0	($88.1)
Generation	$0.0	($2,632.4)	$0.0	$2,632.4	$0.0	$64.3	$0.0	($64.3)	$0.0	$2,568.1
Import	$0.0	($9.1)	$0.0	$9.1	$0.0	($20.2)	$0.0	$20.2	$0.0	$29.2
INC	$0.0	($101.6)	$0.0	$101.6	$0.0	$170.3	$0.0	($170.3)	$0.0	($68.7)
Internal Bilateral	$1,067.7	$1,070.9	$3.2	($0.0)	($22.0)	($22.0)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$144.1	$144.1	$0.0	$0.0	($357.3)	($357.3)	$0.0	($213.2)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($1.4)	($1.7)	($0.4)	$0.0	($0.4)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	$0.0	($1.4)	$0.0	($1.4)
Total	$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	$0.0	$2,501.3

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): 2021

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$24.6	$0.0	$0.0	$24.6	($55.0)	$0.0	$0.0	($55.0)	$0.0	($30.4)
Demand	$54.8	$0.0	$0.0	$54.8	$38.8	$0.0	$0.0	$38.8	$0.0	$93.6
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$2.8	$2.8	$0.0	$0.0	($0.7)	($0.7)	$0.0	$2.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)
Export	($45.0)	$0.0	($0.6)	($45.6)	($7.6)	$0.0	$2.8	($4.7)	$0.0	($50.4)
Generation	$0.0	($1,093.5)	$0.0	$1,093.5	$0.0	$31.7	$0.0	($31.7)	$0.0	$1,061.8
Import	$0.0	($0.4)	$0.0	$0.4	$0.0	$14.5	$0.0	($14.5)	$0.0	($14.1)
INC	$0.0	($33.4)	$0.0	$33.4	$0.0	$60.3	$0.0	($60.3)	$0.0	($26.9)
Internal Bilateral	$377.5	$380.2	$2.7	$0.0	$2.8	$2.8	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$62.8	$62.8	$0.0	$0.0	($102.6)	($102.6)	$0.0	($39.8)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.2)	($0.9)	$0.0	($0.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$0.0	$995.3

Table 11-13 shows the change in total CLMP credits and charges by transaction type in 2021 and 2022. Total negative CLMP credits to generation increased by $1,506.2 million, and total CLMP charges to demand increased by $233.9 million. The total CLMP credits to up to congestion transactions (UTCs) increased by $173.4 million in 2022. Total day-ahead CLMP charges to UTCs increased by $81.3 million in 2022. Balancing CLMP credits to UTCs increased by $254.7 million in 2022.

Table 11-13 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): 2021 to 2022

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($9.5)	$0.0	$0.0	($9.5)	($11.9)	$0.0	$0.0	($11.9)	$0.0	($21.4)
Demand	$142.8	$0.0	$0.0	$142.8	$91.1	$0.0	$0.0	$91.1	$0.0	$233.9
Demand Response	$0.2	$0.0	$0.0	$0.2	($0.4)	$0.0	$0.0	($0.4)	$0.0	($0.2)
Explicit Congestion Only	$0.0	$0.0	($2.0)	($2.0)	$0.0	$0.0	$0.7	$0.7	$0.0	($1.3)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.1)
Export	($29.2)	$0.0	($0.3)	($29.5)	($9.0)	$0.0	$0.8	($8.3)	$0.0	($37.7)
Generation	$0.0	($1,538.9)	$0.0	$1,538.9	$0.0	$32.6	$0.0	($32.6)	$0.0	$1,506.2
Import	$0.0	($8.7)	$0.0	$8.7	$0.0	($34.8)	$0.0	$34.8	$0.0	$43.5
INC	$0.0	($68.2)	$0.0	$68.2	$0.0	$110.0	$0.0	($110.0)	$0.0	($41.8)
Internal Bilateral	$690.1	$690.6	$0.5	($0.0)	($24.8)	($24.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$81.3	$81.3	$0.0	$0.0	($254.7)	($254.7)	$0.0	($173.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($2.1)	($1.5)	$0.6	$0.0	$0.6
Wheel Out	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.0	$0.0	($2.1)	$0.0	($2.1)
Total	$794.5	($925.1)	$79.5	$1,799.1	$42.8	$80.9	($254.8)	($292.8)	$0.0	$1,506.2

Table 11-14 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in 2022. Total CLMP charges to generation decreased by $91.3 million, and total CLMP charges to demand increased by $1.0 million from the dispatch run to the pricing run. The total CLMP credits to DECs increased by $0.7 million, the total CLMP credits to INCs increased by $4.1 million and the total CLMP credits to UTCs increased by $3.3 million from the dispatch run to the pricing run.

Table 11-14 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): 2022

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$9.7	($60.8)	($51.1)	$15.1	($66.9)	($51.8)	$5.4	($6.1)	($0.7)
Demand	$199.2	$127.3	$326.5	$197.6	$129.9	$327.5	($1.6)	$2.6	$1.0
Demand Response	$0.3	($0.5)	($0.2)	$0.3	($0.5)	($0.2)	($0.0)	($0.0)	($0.0)
Explicit Congestion Only	$0.7	($0.0)	$0.7	$0.7	$0.0	$0.7	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	($0.4)	($0.0)	($0.4)	($0.4)	($0.0)	($0.4)	$0.0	$0.0	$0.0
Export	($76.7)	($13.2)	($90.0)	($75.1)	($13.0)	($88.1)	$1.6	$0.2	$1.9
Generation	$2,714.4	($55.0)	$2,659.4	$2,632.4	($64.3)	$2,568.1	($82.1)	($9.2)	($91.3)
Import	$9.6	$20.1	$29.7	$9.1	$20.2	$29.2	($0.5)	$0.1	($0.5)
INC	$102.7	($167.3)	($64.6)	$101.6	($170.3)	($68.7)	($1.1)	($3.0)	($4.1)
Internal Bilateral	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$140.2	($350.2)	($209.9)	$144.1	($357.3)	($213.2)	$3.8	($7.1)	($3.3)
Wheel In	$0.0	($0.3)	($0.3)	$0.0	($0.4)	($0.4)	$0.0	($0.1)	($0.1)
Wheel Out	$0.0	($1.4)	($1.4)	$0.0	($1.4)	($1.4)	$0.0	$0.0	$0.0
Total	$3,099.7	($501.4)	$2,598.4	$3,025.2	($523.9)	$2,501.3	($74.5)	($22.5)	($97.1)

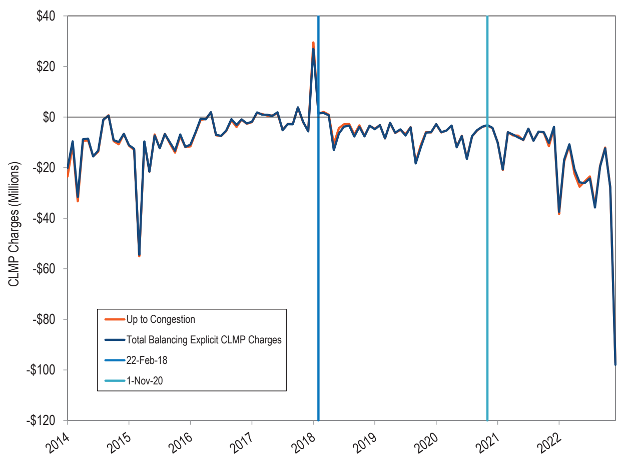
UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-7 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through March 2022. Figure 11-7 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-7, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In 2022, 100.5 percent (-$357.3 million out of -$355.4 million) of negative balancing explicit CLMP charges was incurred by UTCs and -0.5 percent ($1.9 out of -$355.4 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-11). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[19] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[20]

19 For additional information about the FERC order, see the *2021 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
20 172 FERC ¶ 61,046 (2020).

Negative balancing explicit CLMP charges were substantially higher in December than in other months as a result of transmission constraint penalty factors in the real-time market. The total negative balancing explicit CLMP charges on December 7 and 8, and the Elliott days of December 23 through 26, 2022 were 64.1 percent (-$62.3 million out of -$97.2 million) of total negative balancing explicit CLMP charges in December of 2022.

Figure 11-7 Monthly balancing explicit CLMP charges incurred by UTC: 2014 through 2022



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 between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, 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 unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market 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.[21] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[22]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models 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

21 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

22 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 (2016).

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 B. Total day-ahead congestion, which is the difference between CLMP 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 has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. 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 UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-15 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[23]

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-15 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)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays 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.

23 153 FERC ¶ 61,180 (2016).

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire 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 decremental bids and incremental 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.

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 CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP 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 calculating the congestion from an individual constraint, the reference bus for each constraint calculation is 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, congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP 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 11-16 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, for 2022. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. DOM had the largest zonal congestion costs among all control zones in 2022. DOM had $440.6 million in zonal congestion costs, comprised of $541.2 million in zonal day-ahead congestion costs and -$100.6 million in zonal balancing congestion costs. The Brambleton - Evergreen Mills Line, the Greys Point - Harmony Village Line, the Nottingham Series Reactor, the Cumberland – Juniata Line and the AP South Interface contributed $208.1 million, or 47.2 percent of the DOM zonal congestion costs.[24]

As a result of the increased load in the Data Center Alley area of Northern Virginia, two of the top five constraints, in terms of total congestion revenue collected, were in the DOM Zone and one of the top five constraints was located between the APS Zone and the DOM Zone. As a result, in 2022, DOM load paid both more total congestion costs and a larger share due to constraints inside the DOM Zone than in 2021.

Table 11-17 shows the congestion costs by zone for 2021.

24 For additional information about the top 20 constraints that affected each zone, see the *2022 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-16 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$10.3	($19.3)	$1.4	$31.0	$0.2	$2.3	($4.1)	($6.1)	$0.5	$24.4	$24.9
AEP	$155.9	($271.9)	$24.9	$452.7	$7.5	$27.4	($53.0)	($73.0)	$41.1	$338.6	$379.7
APS	$76.9	($117.2)	$8.6	$202.7	$1.7	$12.4	($22.6)	($33.3)	$8.9	$160.5	$169.4
ATSI	$74.0	($138.0)	$11.5	$223.5	$3.8	$14.1	($26.3)	($36.6)	$5.6	$181.3	$186.9
BGE	$40.8	($71.2)	$5.1	$117.0	$1.7	$7.6	($13.6)	($19.5)	$6.2	$91.3	$97.5
COMED	$98.3	($182.6)	$15.7	$296.6	$6.6	$20.9	($34.8)	($49.1)	$24.1	$223.4	$247.4
DAY	$16.8	($33.4)	$2.9	$53.1	$1.1	$3.7	($7.2)	($9.8)	$0.0	$43.3	$43.4
DOM	$337.0	($179.9)	$24.3	$541.2	($5.0)	$32.1	($63.4)	($100.6)	$206.4	$234.1	$440.6
DPL	$50.9	($44.4)	$4.0	$99.4	($2.9)	$3.6	($8.2)	($14.7)	$38.8	$45.9	$84.7
DUKE	$30.2	($49.2)	$4.7	$84.0	$1.8	$5.8	($11.2)	($15.2)	$4.0	$64.8	$68.8
DUQ	$12.5	($20.2)	$1.5	$34.2	$0.8	$2.8	($5.3)	($7.4)	$0.1	$26.8	$26.8
EKPC	$16.0	($26.3)	$2.6	$45.0	$0.9	$2.7	($6.1)	($7.9)	$0.2	$36.9	$37.1
EXT	$20.5	($28.0)	$2.5	$50.9	$1.8	$5.8	($11.0)	($15.1)	$3.9	$31.9	$35.8
JCPLC	$29.7	($55.0)	$3.5	$88.2	$0.5	$6.0	($10.9)	($16.3)	$2.8	$69.1	$71.8
MEC	$21.9	($35.1)	$2.3	$59.2	($0.5)	$3.7	($6.4)	($10.6)	$3.5	$45.1	$48.6
OVEC	$1.1	($1.8)	$1.5	$4.4	$0.1	$0.3	($0.5)	($0.7)	$1.3	$2.3	$3.7
PE	$26.3	($37.7)	$2.8	$66.7	$0.5	$3.9	($7.1)	($10.5)	$5.9	$50.3	$56.2
PECO	$46.3	($85.5)	$5.5	$137.3	$0.5	$8.8	($16.0)	($24.3)	$14.0	$99.0	$113.0
PEPCO	$38.1	($63.4)	$4.9	$106.4	$1.6	$7.0	($12.4)	($17.9)	$0.5	$88.0	$88.5
PPL	$51.6	($115.7)	$8.9	$176.1	($0.4)	$9.5	($17.0)	($26.9)	$47.4	$101.8	$149.2
PSEG	$48.9	($93.4)	$6.4	$148.7	$0.4	$10.2	($17.7)	($27.5)	$5.5	$115.7	$121.2
REC	$2.5	($2.9)	$1.5	$6.9	$0.0	$0.4	($0.6)	($0.9)	$2.0	$3.9	$5.9
Total	$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	$422.9	$2,078.4	$2,501.3

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$3.6	($6.3)	$0.7	$10.6	($0.2)	$1.0	($1.1)	($2.3)	$0.5	$7.8	$8.3
AEP	$53.2	($134.2)	$10.7	$198.1	($2.3)	$17.6	($15.2)	($35.1)	$28.6	$134.4	$163.1
APS	$25.6	($56.5)	$3.6	$85.7	($0.5)	$6.9	($5.9)	($13.3)	$3.5	$68.8	$72.4
ATSI	$23.1	($67.0)	$5.1	$95.1	($0.7)	$8.5	($7.6)	($16.8)	$1.0	$77.3	$78.3
BGE	$15.5	($28.3)	$2.2	$46.0	($0.0)	$4.3	($4.0)	($8.3)	$6.0	$31.8	$37.7
COMED	$32.7	($104.3)	$9.1	$146.0	($0.9)	$13.0	($11.2)	($25.1)	$23.6	$97.3	$121.0
DAY	$4.0	($17.3)	$1.3	$22.6	($0.2)	$2.3	($2.1)	($4.7)	$0.0	$18.0	$18.0
DOM	$86.1	($83.7)	$9.4	$179.3	($4.1)	$14.9	($15.7)	($34.8)	$39.6	$104.9	$144.5
DPL	$45.5	($7.0)	$3.1	$55.7	($1.8)	$1.7	($2.1)	($5.6)	$34.5	$15.6	$50.0
DUKE	$7.8	($25.4)	$2.1	$35.3	($0.3)	$3.6	($3.4)	($7.3)	$1.4	$26.6	$28.0
DUQ	$2.6	($11.2)	$0.6	$14.5	($0.1)	$1.7	($1.5)	($3.3)	$0.2	$11.0	$11.1
EKPC	$3.6	($13.6)	$1.0	$18.2	($0.2)	$1.9	($1.7)	($3.7)	$0.0	$14.4	$14.4
EXT	$9.2	($13.4)	$1.7	$24.3	($2.2)	$5.9	($4.6)	($12.7)	$1.0	$10.6	$11.6
JCPLC	$7.4	($17.2)	$1.3	$26.0	($0.3)	$2.5	($2.4)	($5.2)	$0.0	$20.7	$20.7
MEC	$12.3	($14.9)	$1.1	$28.3	($2.7)	$2.2	($2.3)	($7.2)	$5.9	$15.2	$21.1
OVEC	$0.2	($0.6)	$0.1	$0.9	($0.0)	$0.1	($0.1)	($0.3)	$0.1	$0.6	$0.7
PE	$11.1	($18.1)	$1.6	$30.8	($0.8)	$3.2	($2.2)	($6.3)	$2.5	$22.1	$24.5
PECO	$20.2	($30.0)	$2.3	$52.5	($0.7)	$4.3	($4.2)	($9.2)	$7.3	$36.1	$43.3
PEPCO	$14.0	($24.5)	$2.0	$40.6	($0.0)	$3.9	($3.5)	($7.5)	$0.2	$32.9	$33.1
PPL	$15.9	($39.8)	$3.4	$59.1	($0.8)	$4.8	($4.5)	($10.0)	$13.5	$35.6	$49.1
PSEG	$16.2	($32.5)	$3.0	$51.7	($1.3)	$5.3	($5.3)	($11.8)	($0.1)	$39.9	$39.9
REC	$2.1	($0.9)	$1.7	$4.8	($0.1)	$0.2	($0.2)	($0.5)	$3.0	$1.3	$4.3
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$172.4	$822.8	$995.3

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In 2022, the total congestion costs associated with these special cases were $20.1 million or 0.8 percent of the total congestion costs. Table 11-16 and Table 11-17 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[25]

Table 11-18 and Table 11-19 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in 2022 or 2021.

Table 11-18 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): 2022

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$31.0	$31.0	$0.0	($0.0)	$0.0	$0.0	$0.0	($6.1)	($6.1)	$24.9	($0.1)	(0.2%)
AEP	$0.0	($0.2)	$0.0	$1.8	$0.0	$451.3	$452.9	$0.0	($0.8)	$0.0	$0.0	$0.0	($72.2)	($73.0)	$379.9	$0.8	0.2%
APS	$0.0	($0.1)	$0.0	$0.0	$0.0	$202.9	$202.8	$0.0	($0.3)	$0.0	$0.0	$0.0	($33.0)	($33.3)	$169.5	($0.4)	(0.2%)
ATSI	$0.0	($0.1)	$0.0	$3.3	$0.0	$220.3	$223.5	$0.0	($0.4)	$0.0	$0.0	$0.0	($36.2)	($36.6)	$187.0	$2.9	1.5%
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$117.1	$117.0	$0.0	($0.2)	$0.0	$0.0	$0.0	($19.4)	($19.5)	$97.5	($0.2)	(0.2%)
COMED	$0.3	($0.1)	$0.0	$4.4	$0.0	$291.9	$296.4	$0.0	($0.6)	$0.0	$0.0	$0.0	($48.5)	($49.1)	$247.3	$4.0	1.6%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$53.1	$53.1	$0.0	($0.1)	$0.0	$0.0	$0.0	($9.7)	($9.8)	$43.3	($0.1)	(0.3%)
DOM	$0.0	($0.1)	$0.0	$0.7	$0.0	$540.0	$540.6	$0.0	($0.6)	$0.0	$0.0	$0.0	($100.0)	($100.6)	$440.0	$0.0	0.0%
DPL	$0.1	($0.0)	$0.0	$0.0	$0.0	$99.4	$99.5	$0.0	($0.1)	$0.0	$0.0	$0.0	($14.6)	($14.7)	$84.8	($0.0)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.3	$0.0	$83.7	$84.0	$0.0	($0.2)	$0.0	$0.0	$0.0	($15.0)	($15.2)	$68.8	$0.1	0.2%
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$34.2	$34.2	$0.0	($0.1)	$0.0	$0.0	$0.0	($7.3)	($7.4)	$26.8	($0.1)	(0.3%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$45.0	$45.0	$0.0	($0.1)	$0.0	$0.0	$0.0	($7.8)	($7.9)	$37.1	($0.1)	(0.3%)
EXT	$3.6	($0.0)	$0.0	$0.2	$0.0	$47.1	$51.0	$0.0	($0.3)	$0.0	$0.0	$0.0	($14.8)	($15.1)	$35.8	$3.6	9.9%
JCPLC	$2.8	($0.0)	$0.0	$0.0	$0.0	$85.5	$88.3	$0.0	($0.1)	$0.0	$0.0	$0.0	($16.2)	($16.3)	$72.0	$2.7	3.7%
MEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$59.2	$59.2	$0.0	($0.1)	$0.0	$0.0	$0.0	($10.6)	($10.6)	$48.6	($0.0)	(0.1%)
OVEC	$0.0	($0.0)	$0.0	$1.4	$0.0	$3.0	$4.4	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.7)	($0.7)	$3.7	$1.4	36.5%
PE	$0.0	($0.0)	$0.0	$0.1	$0.0	$66.7	$66.8	$0.0	($0.1)	$0.0	$0.0	$0.0	($10.4)	($10.5)	$56.3	($0.0)	(0.0%)
PECO	$0.0	($0.1)	$0.0	$0.0	$0.0	$137.4	$137.4	$0.0	($0.2)	$0.0	$0.0	$0.0	($24.1)	($24.3)	$113.1	($0.2)	(0.2%)
PEPCO	$0.0	($0.0)	$0.0	$0.1	$0.0	$106.3	$106.4	$0.0	($0.2)	$0.0	$0.0	$0.0	($17.7)	($17.9)	$88.5	($0.1)	(0.1%)
PPL	$0.4	($0.1)	$0.0	$6.2	$0.0	$169.7	$176.2	$0.0	($0.2)	$0.0	$0.0	$0.0	($26.7)	($26.9)	$149.3	$6.3	4.2%
PSEG	$0.0	($0.1)	$0.0	$0.0	$0.0	$148.8	$148.7	$0.0	($0.2)	$0.0	$0.0	$0.0	($27.2)	($27.5)	$121.3	($0.3)	(0.2%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.9	$6.9	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.9)	($0.9)	$5.9	($0.0)	(0.1%)
Total	$7.2	($1.1)	$0.0	$18.7	$0.0	$3,000.3	$3,025.2	$0.0	($4.9)	$0.0	$0.1	$0.0	($519.2)	($523.9)	$2,501.3	$20.1	0.8%

25 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-19 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): 2021

	CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing										
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.5	$10.6	$0.0	($0.0)	$0.0	$0.0	($0.0)	($2.2)	($2.3)	$8.3	($0.0)	(0.5%)
AEP	$0.0	($0.0)	$0.0	$0.4	$0.0	$197.8	$198.1	$0.0	($0.5)	$0.0	($0.0)	($0.3)	($34.3)	($35.1)	$163.1	($0.5)	(0.3%)
APS	$0.0	($0.0)	$0.0	$0.2	$0.0	$85.6	$85.7	$0.0	($0.2)	$0.0	($0.0)	($0.1)	($13.0)	($13.3)	$72.4	($0.2)	(0.2%)
ATSI	$0.0	($0.0)	$0.0	$0.0	$0.0	$95.1	$95.1	$0.0	($0.3)	$0.0	$0.0	($0.1)	($16.4)	($16.8)	$78.3	($0.4)	(0.5%)
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$46.0	$46.0	$0.0	($0.1)	$0.0	$0.0	($0.1)	($8.1)	($8.3)	$37.7	($0.2)	(0.5%)
COMED	$0.8	($0.0)	$0.0	$4.2	$0.0	$141.0	$146.0	$0.0	($0.4)	$0.0	$0.0	($0.2)	($24.5)	($25.1)	$121.0	$4.4	3.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$22.6	$22.6	$0.0	($0.1)	$0.0	$0.0	($0.0)	($4.5)	($4.7)	$18.0	($0.1)	(0.6%)
DOM	$0.0	($0.0)	$0.0	$0.0	$0.0	$179.2	$179.3	$0.0	($0.4)	$0.0	$0.0	($0.2)	($34.1)	($34.8)	$144.5	($0.6)	(0.4%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$55.7	$55.7	$0.0	($0.1)	$0.0	$0.0	($0.0)	($5.5)	($5.6)	$50.0	($0.1)	(0.2%)
DUKE	$0.0	($0.0)	$0.0	$0.4	$0.0	$34.9	$35.3	($0.0)	($0.1)	$0.0	$0.0	($0.1)	($7.1)	($7.3)	$28.0	$0.3	1.0%
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$14.5	$14.5	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.3)	($3.3)	$11.1	($0.1)	(0.7%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$18.2	$18.2	$0.0	($0.1)	$0.0	$0.0	($0.0)	($3.7)	($3.7)	$14.4	($0.1)	(0.6%)
EXT	$0.9	($0.0)	$0.0	$0.2	$0.0	$23.3	$24.3	($0.0)	($2.7)	$0.0	$0.0	($0.0)	($9.9)	($12.7)	$11.6	($1.7)	(14.8%)
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.0	$26.0	$26.0	$0.0	($0.1)	$0.0	$0.0	($0.0)	($5.1)	($5.2)	$20.7	($0.1)	(0.6%)
MEC	$0.0	($0.0)	$0.0	$0.4	$0.0	$27.9	$28.3	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($7.1)	($7.2)	$21.1	$0.3	1.3%
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.8	$0.9	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.3)	($0.3)	$0.7	$0.1	11.8%
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$30.8	$30.8	$0.0	($0.1)	$0.0	($0.6)	($0.0)	($5.5)	($6.3)	$24.5	($0.7)	(3.0%)
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$52.5	$52.5	$0.0	($0.2)	$0.0	$0.0	($0.1)	($8.9)	($9.2)	$43.3	($0.2)	(0.6%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$40.6	$40.6	$0.0	($0.1)	$0.0	$0.0	($0.1)	($7.3)	($7.5)	$33.1	($0.2)	(0.5%)
PPL	$0.0	($0.0)	$0.0	$0.8	$0.0	$58.4	$59.1	($0.0)	($0.2)	$0.0	$0.0	($0.1)	($9.8)	($10.0)	$49.1	$0.5	1.1%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$51.7	$51.7	$0.0	($0.2)	$0.0	$0.0	($0.1)	($11.6)	($11.8)	$39.9	($0.3)	(0.6%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.8	$4.8	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.5)	($0.5)	$4.3	($0.0)	(0.2%)
Total	$1.8	($0.3)	$0.0	$6.7	$0.1	$1,217.8	$1,226.2	($0.0)	($6.0)	$0.0	($0.6)	($1.8)	($222.6)	($230.9)	$995.3	$0.0	0.0%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-20 compares the congestion costs between the dispatch run and the pricing run in 2022. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to decrease $74.5 million (or 2.4 percent), caused negative balancing congestion costs to increase $22.5 million (or 4.5 percent), and caused total congestion costs to decrease $97.1 million (or 3.7 percent) from the dispatch run to the pricing run in 2022. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-20 Total congestion by dispatch and pricing run (Dollars (Millions)) 2022

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$32.1	($5.8)	$26.2	$31.0	($6.1)	$24.9	($1.1)	($0.3)	($1.4)
AEP	$457.7	($70.0)	$387.7	$452.7	($73.0)	$379.7	($5.0)	($3.0)	($8.0)
APS	$206.2	($31.7)	$174.5	$202.7	($33.3)	$169.4	($3.5)	($1.6)	($5.0)
ATSI	$227.5	($34.9)	$192.6	$223.5	($36.6)	$186.9	($4.0)	($1.7)	($5.6)
BGE	$120.4	($18.7)	$101.8	$117.0	($19.5)	$97.5	($3.4)	($0.9)	($4.3)
COMED	$304.7	($47.1)	$257.6	$296.6	($49.1)	$247.4	($8.1)	($2.0)	($10.2)
DAY	$54.9	($9.4)	$45.6	$53.1	($9.8)	$43.4	($1.8)	($0.4)	($2.2)
DOM	$567.0	($97.4)	$469.6	$541.2	($100.6)	$440.6	($25.8)	($3.2)	($29.0)
DPL	$100.8	($13.3)	$87.5	$99.4	($14.7)	$84.7	($1.4)	($1.4)	($2.8)
DUKE	$86.2	($14.6)	$71.7	$84.0	($15.2)	$68.8	($2.2)	($0.6)	($2.8)
DUQ	$35.5	($7.1)	$28.4	$34.2	($7.4)	$26.8	($1.3)	($0.3)	($1.6)
EKPC	$45.5	($7.6)	$37.9	$45.0	($7.9)	$37.1	($0.5)	($0.3)	($0.8)
EXT	$51.2	($14.5)	$36.6	$50.9	($15.1)	$35.8	($0.2)	($0.6)	($0.8)
JCPLC	$87.7	($15.5)	$72.1	$88.2	($16.3)	$71.8	$0.5	($0.8)	($0.3)
MEC	$60.6	($10.3)	$50.3	$59.2	($10.6)	$48.6	($1.4)	($0.3)	($1.7)
OVEC	$3.1	($0.7)	$2.4	$4.4	($0.7)	$3.7	$1.3	($0.0)	$1.3
PE	$67.7	($10.0)	$57.8	$66.7	($10.5)	$56.2	($1.0)	($0.5)	($1.5)
PECO	$141.2	($23.1)	$118.1	$137.3	($24.3)	$113.0	($3.9)	($1.2)	($5.1)
PEPCO	$109.6	($17.1)	$92.5	$106.4	($17.9)	$88.5	($3.2)	($0.7)	($4.0)
PPL	$180.1	($25.8)	$154.3	$176.1	($26.9)	$149.2	($3.9)	($1.1)	($5.1)
PSEG	$153.1	($26.0)	$127.1	$148.7	($27.5)	$121.2	($4.4)	($1.4)	($5.9)
REC	$7.1	($0.9)	$6.2	$6.9	($0.9)	$5.9	($0.2)	($0.0)	($0.2)
Total	$3,099.7	($501.4)	$2,598.4	$3,025.2	($523.9)	$2,501.3	($74.5)	($22.5)	($97.1)

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for 2021 and 2022. Total congestion costs were significantly higher in every month of 2022 than every month of 2021. Total day-ahead congestion costs in 2022 were highest in January mainly due to outages affecting the Greys Point – Harmony Village Line and cold weather in January.

Total negative balancing congestion costs in 2022 were high in January and December. The top five constraints that contributed to the total balancing congestion costs in 2022 were the Brambleton - Evergreen Mills Line, Shadeland - Lafayette South Flowgate, AEP – DOM Interface, the Nottingham Series Reactor, and the Bedington - Black Oak Interface. These five constraints accounted for 31.1 percent of the total balancing congestion costs in 2022.

In 2022, total negative balancing congestion costs were highest in January. The negative balancing congestion in January was as a result of significant day-ahead and real-time pricing and modeling differences affecting the Greys Point - Harmony Village Line. January 16, 2022 contributed -$18.6 million (15.0 percent) of the -$123.8 million negative balancing congestion costs in January of 2022. The Bedington – Black Oak, AP South, East and AEP – DOM interfaces contributed 76.9 percent of that -$18.6 million in total balancing congestion as a result of modeling differences between real-time and day-ahead market, tripping of units and the load forecast error.

December had the second highest total negative balancing congestion costs in 2022, with 49.2 percent of total balancing congestion costs in December occurred on December 7, 8 and 28 of 2022. The top two constraints that contributed most to the negative balancing congestion costs on December 7 and 8 of 2022 were the Brambleton - Evergreen Mills Line and the Idylwood – Clark Line that locate in the DOM Zone. Brambleton - Evergreen Mills Line and the Idylwood – Clark Line both contributed transmission constraint penalty violations in the real-time market on December 7 and 8 of 2022. The main source of negative balancing congestions for Brambleton - Evergreen Mills Line and the Idylwood – Clark Line in December were UTCs on December 7 and 8 of 2022.

Total congestion costs in 2022 were highest in May and lowest in March. The highest day-ahead congestion costs occurred, in order of cost, on May 21, May 22, and May 20, 2022, as a result of constraint violations that caused transmission penalty factors to set prices in the day-ahead market and hot weather alert events on May 20, 2022 and May 21, 2022.[26] In May, the top three constraints by total day-ahead congestion costs were the Brambleton - Evergreen Mills Line, the Idylwood – Clark Line and the Nottingham Series Reactor. The Brambleton - Evergreen Mills Line had a constraint violation that caused a transmission penalty factor to set price on May 22, 2022 and the Idylwood – Clark Line had constraint violations at four hours that caused a transmission penalty factor to set price on May 21, 2022 in the day-ahead market.

Table 11-21 Monthly congestion costs by market (Dollars (Millions)): 2021 and 2022

	Congestion Costs (Millions)							
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$53.2	($24.1)	($0.0)	$29.1	$443.2	($123.8)	$0.0	$319.4
Feb	$90.3	($53.4)	$0.0	$36.9	$158.9	($42.6)	$0.0	$116.3
Mar	$81.0	($25.8)	$0.0	$55.2	$99.3	($24.7)	$0.0	$74.5
Apr	$81.8	($18.0)	($0.0)	$63.9	$145.9	($31.3)	($0.0)	$114.6
May	$104.4	($10.5)	$0.0	$94.0	$406.4	($52.2)	($0.0)	$354.2
Jun	$91.0	($15.9)	$0.0	$75.1	$202.0	($37.6)	$0.0	$164.4
Jul	$78.7	($3.4)	$0.0	$75.4	$223.6	($33.1)	$0.0	$190.5
Aug	$112.1	($16.6)	$0.0	$95.5	$355.6	($46.1)	($0.0)	$309.5
Sep	$97.0	($7.2)	$0.0	$89.8	$248.5	($28.7)	($0.0)	$219.8
Oct	$113.5	($14.4)	$0.0	$99.1	$161.4	($16.7)	($0.0)	$144.8
Nov	$209.6	($34.3)	$0.0	$175.3	$215.3	($28.4)	($0.0)	$186.9
Dec	$113.6	($7.3)	$0.0	$106.3	$365.0	($58.6)	$0.0	$306.4
Total	$1,226.2	($230.9)	$0.0	$995.3	$3,025.2	($523.9)	($0.0)	$2,501.3

26 PJM. System Operations Subcommittee. PJM Operations Summary May 2022 Operations (June 2, 2022) <https://www.pjm.com/-/media/committees-groups/subcommittees/sos/2022/20220602/20220602-item-04-operations-summary-may-2022.ashx>.

Figure 11-8 shows PJM monthly total congestion cost for the 2008 through 2022.

Figure 11-8 Monthly total congestion cost (Dollars (Millions)): 2008 through 2022

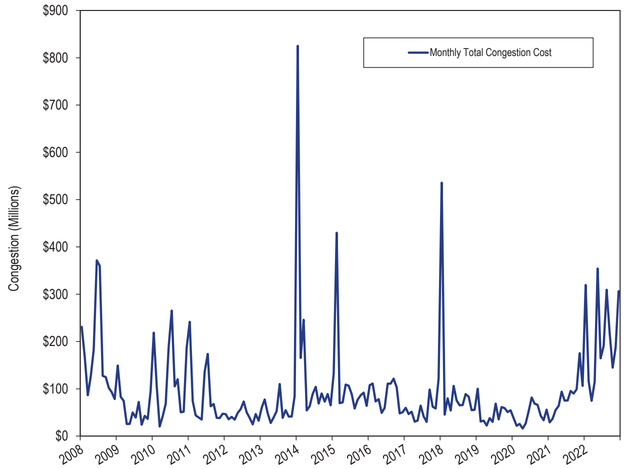


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type in 2021 and 2022. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in 2022 and 2021. In 2022, 63.9 percent of the total credits to virtuals went to UTCs, compared to 41.0 percent in 2021. In 2022, the average hourly cleared UTC MW increased by 87.8 percent, compared to 2021.

Table 11-22 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): 2021 and 2022

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$3.0	($8.0)	($5.0)	$0.5	($0.1)	$0.4	$4.0	($10.0)	($6.0)	($10.5)
	Feb	$11.8	($24.7)	($12.9)	$0.6	($4.0)	($3.5)	$7.9	($20.9)	($13.0)	($29.4)
	Mar	$6.7	($7.7)	($1.0)	$4.0	($8.1)	($4.2)	$4.9	($6.0)	($1.1)	($6.2)
	Apr	($1.1)	$1.9	$0.8	$4.9	($8.4)	($3.5)	$3.1	($7.2)	($4.2)	($6.8)
	May	$0.5	($3.1)	($2.7)	$2.4	($2.6)	($0.2)	$5.5	($7.4)	($1.9)	($4.8)
	Jun	$4.2	($6.5)	($2.3)	$0.9	($2.9)	($2.0)	$6.8	($9.2)	($2.3)	($6.6)
	Jul	$2.6	($2.3)	$0.2	$0.2	($0.7)	($0.5)	$6.0	($4.6)	$1.4	$1.1
	Aug	$5.2	($5.0)	$0.2	$0.0	($2.8)	($2.8)	$4.6	($9.3)	($4.7)	($7.3)
	Sep	$1.0	($0.7)	$0.2	$2.1	($3.8)	($1.7)	$5.2	($5.8)	($0.6)	($2.1)
	Oct	($4.3)	$2.3	($2.0)	$4.2	($6.9)	($2.7)	$4.9	($6.1)	($1.2)	($5.9)
	Nov	($2.4)	($1.5)	($3.9)	$12.4	($16.9)	($4.5)	$7.2	($11.5)	($4.3)	($12.7)
	Dec	($2.6)	$0.5	($2.1)	$1.1	($3.0)	($1.9)	$2.6	($4.5)	($1.9)	($5.9)
	Total	$24.6	($55.0)	($30.4)	$33.4	($60.3)	($26.9)	$62.8	($102.6)	($39.8)	($97.2)
2022	Jan	$27.5	($45.7)	($18.3)	$4.4	($22.0)	($17.6)	$10.5	($38.3)	($27.8)	($63.7)
	Feb	$5.9	($20.9)	($15.1)	$5.4	($7.1)	($1.6)	$12.4	($17.6)	($5.1)	($21.8)
	Mar	($0.9)	($3.1)	($4.0)	$7.3	($9.5)	($2.2)	$9.7	($11.3)	($1.6)	($7.7)
	Apr	($3.0)	$3.1	$0.1	$12.5	($19.4)	($6.9)	$10.1	($22.4)	($12.3)	($19.1)
	May	($9.0)	$15.0	$6.0	$19.5	($28.8)	($9.2)	$14.9	($27.6)	($12.6)	($15.8)
	Jun	$1.8	($4.0)	($2.2)	$4.5	($8.3)	($3.8)	$10.5	($25.5)	($15.0)	($21.0)
	Jul	$2.0	($6.8)	($4.8)	$4.2	($6.5)	($2.3)	$12.1	($23.5)	($11.4)	($18.5)
	Aug	$1.8	$1.0	$2.7	$6.7	($17.7)	($10.9)	$16.3	($34.9)	($18.6)	($26.8)
	Sep	($0.6)	($1.0)	($1.6)	$6.2	($8.3)	($2.0)	$11.4	($19.3)	($7.9)	($11.6)
	Oct	($3.6)	$1.5	($2.1)	$7.8	($10.1)	($2.4)	$2.9	($12.0)	($9.2)	($13.6)
	Nov	($5.4)	$6.3	$0.9	$10.9	($15.1)	($4.2)	$11.6	($27.8)	($16.2)	($19.5)
	Dec	($1.3)	($12.2)	($13.5)	$12.0	($17.6)	($5.6)	$21.8	($97.2)	($75.3)	($94.5)
	Total	$15.1	($66.9)	($51.8)	$101.6	($170.3)	($68.7)	$144.1	($357.3)	($213.2)	($333.7)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour the result is one constrained hour and two congestion event hours. 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 2022, there were 73,031 day-ahead, congestion event hours compared to 56,617 day-ahead congestion event hours in 2021. Of the day-ahead congestion event hours in 2022, only 13,441 (18.4 percent) were also constrained in the real-time energy market (Table 11-25). In 2022, there were 27,744 real-time, congestion event hours compared to 23,068 real-time, congestion event hours in 2021. Of the real-time congestion event hours in 2022, 13,741 (49.5 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed $929.8 million, or 37.2 percent, of the total PJM congestion costs in 2022. The top five constraints were the Nottingham Series Reactor, the Brambleton - Evergreen Mills Line, the Cumberland - Juniata Line, the AP South Interface, and the Beaumeade Circuit Breaker.

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours increased on all types of facilities in 2022. Congestion event hours on lines increased by 9,843 congestion event hours from 36,474 day-ahead, congestion event hours in 2021 to 46,317 day-ahead congestion event hours in 2022 (Table 11-25).

Real-time, congestion event hours increased on all types of facilities except transformers in 2022 (Table 11-26). Flowgates increased by 2,319 congestion event hours from 6,340 real-time, congestion event hours in 2021 to 8,659 real-time congestion event hours in 2022.

Day-ahead congestion costs increased on all types of facilities except transformers in 2022 compared to 2021 (Table 11-23).

Negative balancing congestion costs increased on all types of facilities except transformers in 2022 compared to 2021 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing 2022 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[27] [28]

Table 11-23 Congestion summary (By facility type): 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($98.6)	($437.7)	$14.7	$353.8	$5.5	$30.9	($104.4)	($129.8)	$224.0	11,878	8,659
Interface	$78.9	($198.9)	$8.6	$286.4	($16.3)	$47.6	($37.2)	($101.1)	$185.3	1,249	911
Line	$716.3	($913.3)	$91.2	$1,720.7	$1.9	$61.0	($170.6)	($229.6)	$1,491.1	46,317	12,379
Transformer	$100.4	($106.6)	$10.6	$217.6	($3.8)	$7.1	($11.7)	($22.7)	$194.9	8,094	2,187
Other	$401.0	($7.6)	$21.7	$430.3	$35.2	$44.3	($31.6)	($40.7)	$389.6	5,493	3,608
Unclassified	$8.3	($8.2)	($0.1)	$16.4	$0.0	$0.0	$0.0	$0.0	$16.4	NA	NA
Total	$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	$2,501.3	73,031	27,744

27 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP 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.

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

Table 11-24 Congestion summary (By facility type): 2021

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($49.6)	($202.9)	$6.3	$159.6	$4.2	$32.6	($16.0)	($44.4)	$115.2	8,640	6,340
Interface	$0.1	($1.6)	$0.1	$1.9	$0.2	$0.8	($0.9)	($1.5)	$0.5	38	97
Line	$232.5	($375.3)	$43.7	$651.5	($20.5)	$49.4	($62.1)	($132.0)	$519.4	36,474	11,147
Transformer	$114.3	($161.5)	$7.7	$283.5	($17.6)	$7.7	($10.4)	($35.7)	$247.7	7,393	2,335
Other	$114.5	($5.7)	$9.4	$129.6	$13.5	$18.8	($10.2)	($15.5)	$114.1	4,072	3,149
Unclassified	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.6	($1.1)	($1.8)	($1.6)	NA	NA
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	56,617	23,068

Table 11-25 and Table 11-26 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 11-25.[29]

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 11-26.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in 2022. The number of congestion event hours in the day-ahead energy market was about two and half times the number of congestion event hours in the real-time energy market.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-25 Congestion event hours (day-ahead against real-time): 2021 and 2022

	Congestion Event Hours					
	2021			2022		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	8,640	2,467	28.6%	11,878	3,426	28.8%
Interface	38	7	18.4%	1,249	228	18.3%
Line	36,474	5,388	14.8%	46,317	5,497	11.9%
Transformer	7,393	1,438	19.5%	8,094	1,276	15.8%
Other	4,072	1,758	43.2%	5,493	3,014	54.9%
Total	56,617	11,058	19.5%	73,031	13,441	18.4%

29 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 11-26 Congestion event hours (real-time against day-ahead): 2021 and 2022

Congestion Event Hours						
	2021			2022		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	6,340	2,477	39.1%	8,659	3,439	39.7%
Interface	97	7	7.2%	911	271	29.7%
Line	11,147	5,438	48.8%	12,379	5,714	46.2%
Transformer	2,335	1,455	62.3%	2,187	1,286	58.8%
Other	3,149	1,771	56.2%	3,608	3,031	84.0%
Total	23,068	11,148	48.3%	27,744	13,741	49.5%

Table 11-27 shows congestion costs by facility voltage class for 2022. Congestion costs in 2022 increased for all facility voltage classes except 161 kV facilities compared to 2021.

Table 11-27 Congestion summary (By facility voltage): 2022

CLMP Credits and Charges (Millions)												
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.7)	($7.7)	$0.7	$7.6	$1.2	$0.9	($3.0)	($2.7)	$4.9	121	60
500	$157.1	($294.5)	$14.2	$465.7	($15.6)	$47.5	($47.7)	($110.8)	$355.0	4,053	1,718
345	($55.4)	($263.9)	$17.5	$226.0	($0.9)	($20.5)	($49.1)	($29.5)	$196.5	7,868	2,719
230	$860.8	($777.6)	$67.5	$1,706.0	$49.8	$97.0	($170.0)	($217.2)	$1,488.8	26,434	10,967
220	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
161	($0.6)	($4.2)	$0.9	$4.5	$0.0	$0.7	($1.1)	($1.8)	$2.7	365	451
138	$12.1	($352.6)	$34.1	$398.8	$8.1	$50.4	($74.4)	($116.8)	$282.1	21,276	9,068
115	$199.9	$34.8	$8.8	$173.9	($18.1)	$17.0	($9.4)	($44.5)	$129.3	7,827	2,484
69	$24.8	$2.0	$3.1	$25.9	($2.1)	($2.2)	($1.0)	($0.9)	$25.0	5,060	246
4.1	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	15	0
1	($0.0)	($0.4)	$0.0	$0.4	$0.1	$0.2	$0.3	$0.2	$0.6	12	31
Unclassified	$8.3	($8.2)	($0.1)	$16.4	$0.0	$0.0	$0.0	$0.0	$16.4	NA	NA
Total	$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	$2,501.3	73,031	27,744

Table 11-28 Congestion summary (By facility voltage): 2021

CLMP Credits and Charges (Millions)											
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.9)	($3.5)	$0.1	$2.7	($0.5)	$0.3	($0.4)	($1.2)	$1.5	46	16
500	$111.6	($131.0)	$7.0	$249.6	$6.5	$17.9	($14.4)	($25.7)	$223.9	4,018	2,949
345	($17.7)	($85.6)	$5.0	$73.0	($3.2)	$8.3	($7.0)	($18.6)	$54.4	4,095	1,763
230	$270.1	($211.5)	$30.5	$512.1	($14.5)	$28.1	($36.7)	($79.3)	$432.8	15,627	6,333
220	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	($0.0)	0	9
161	($2.7)	($8.6)	$0.4	$6.2	($0.4)	$0.5	($1.9)	($2.7)	$3.5	424	475
138	($19.1)	($281.4)	$16.8	$279.1	($1.0)	$44.3	($31.5)	($76.8)	$202.3	19,983	8,407
115	$48.3	($23.0)	$3.7	$75.0	($6.5)	$5.7	($5.3)	($17.6)	$57.3	5,680	2,411
69	$22.2	($2.4)	$3.8	$28.4	($0.3)	$2.9	($1.2)	($4.4)	$24.0	6,744	583
4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
1	$0.0	$0.0	$0.0	$0.0	($0.3)	$1.3	($1.1)	($2.7)	($2.7)	0	122
Unclassified	$0.0	($0.1)	$0.0	$0.1	($0.0)	$0.6	($1.1)	($1.7)	($1.6)	NA	NA
Total	$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	56,617	23,068

Constraint Frequency

Table 11-29 lists the constraints for 2021 and 2022 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from 2021 to 2022. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 2022. In Table 11-30, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2021 to 2022.

Table 11-29 Top 25 constraints: 2021 and 2022

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2021	2022	Change	2021	2022	Change	2021	2022	Change	2021	2022	Change
1	Nottingham	Other	2,068	4,645	2,577	1,280	3,066	1,786	23.6%	53%	29%	15%	35%	20%
2	Prest - Tibb	Flowgate	1,129	1,589	460	995	1,341	346	13%	18%	5%	11%	15%	4%
3	Boonetown - South Reading	Line	299	1,717	1,418	191	1,069	878	3%	20%	16%	2%	12%	10%
4	Lenox - North Meshoppen	Line	926	1,152	226	1,156	1,145	(11)	11%	13%	3%	13%	13%	(0%)
5	Shadeland - Lafayette South	Flowgate	19	1,110	1,091	10	1,031	1,021	0%	13%	12%	0%	12%	12%
6	Haumesser Road - Steward	Line	739	1,474	735	430	420	(10)	8%	17%	8%	5%	5%	(0%)
7	Mountain	Transformer	397	1,839	1,442	0	0	0	5%	21%	16%	0%	0%	0%
8	Lackawanna	Transformer	0	940	940	0	841	841	0%	11%	11%	0%	10%	10%
9	Cumberland - Juniata	Line	645	1,206	561	256	512	256	7%	14%	6%	3%	6%	3%
10	Easton - Emuni	Line	714	1,673	959	5	0	(5)	8%	19%	11%	0%	0%	(0%)
11	Brambleton - Evergreen Mills	Line	161	987	826	22	591	569	2%	11%	9%	0%	7%	6%
12	Allen - R.P. Mone	Line	0	1,189	1,189	2	182	180	0%	14%	14%	0%	2%	2%
13	Northwest Tap - Purdue	Flowgate	1,304	702	(602)	1,170	612	(558)	15%	8%	(7%)	13%	7%	(6%)
14	Greys Point - Harmony Village	Line	92	763	671	44	548	504	1%	9%	8%	1%	6%	6%
15	Chicago Ave - Praxair	Flowgate	43	733	690	31	513	482	0%	8%	8%	0%	6%	6%
16	Gardners - Texas Eastern	Line	1,451	1,019	(432)	226	140	(86)	17%	12%	(5%)	3%	2%	(1%)
17	Ramapo (ConEd) - S Mahwah (RECO)	Line	1,251	1,126	(125)	0	0	0	14%	13%	(1%)	0%	0%	0%
18	Maroa E - Goose Creek	Flowgate	261	710	449	126	351	225	3%	8%	5%	1%	4%	3%
19	Howard - Melmore	Line	0	749	749	0	211	211	0%	9%	9%	0%	2%	2%
20	Bergen - Hudson	Line	501	907	406	0	0	0	6%	10%	5%	0%	0%	0%
21	Roxbury - Shade Gap	Line	151	858	707	22	30	8	2%	10%	8%	0%	0%	0%
22	DoeX530	Transformer	77	831	754	0	0	0	1%	9%	9%	0%	0%	0%
23	Sayreville - Sayreville	Line	31	808	777	0	0	0	0%	9%	9%	0%	0%	0%
24	AP South	Interface	10	568	558	18	229	211	0%	6%	6%	0%	3%	2%
25	East Towanda - Hillside	Line	48	406	358	102	358	256	1%	5%	4%	1%	4%	3%

Table 11-30 Top 25 constraints year to year change in occurrence: 2021 and 2022

			Congestion Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2021	2022	Change	2021	2022	Change	2021	2022	Change	2021	2022	Change
1	Nottingham	Other	2,068	4,645	2,577	1,280	3,066	1,786	24%	53%	29%	15%	35%	20%
2	Brighton	Other	1,096	7	(1,089)	1,478	7	(1,471)	13%	0%	(12%)	17%	0%	(17%)
3	Boonetown - South Reading	Line	299	1,717	1,418	191	1,069	878	3%	20%	16%	2%	12%	10%
4	Three Mile Island	Transformer	1,504	0	(1,504)	693	0	(693)	17%	0%	(17%)	8%	0%	(8%)
5	Shadeland - Lafayette South	Flowgate	19	1,110	1,091	10	1,031	1,021	0%	13%	12%	0%	12%	12%
6	East Lima - Haviland	Line	1,591	526	(1,065)	825	93	(732)	18%	6%	(12%)	9%	1%	(8%)
7	Lackawanna	Transformer	0	940	940	0	841	841	0%	11%	11%	0%	10%	10%
8	Bagley - Raphael Road	Line	1,004	0	(1,004)	679	0	(679)	11%	0%	(11%)	8%	0%	(8%)
9	Sandburg	Flowgate	870	0	(870)	732	6	(726)	10%	0%	(10%)	8%	0%	(8%)
10	Mountain	Transformer	397	1,839	1,442	0	0	0	5%	21%	16%	0%	0%	0%
11	Brambleton - Evergreen Mills	Line	161	987	826	22	591	569	2%	11%	9%	0%	7%	6%
12	Allen - R.P. Mone	Line	0	1,189	1,189	2	182	180	0%	14%	14%	0%	2%	2%
13	Greys Point - Harmony Village	Line	92	763	671	44	548	504	1%	9%	8%	1%	6%	6%
14	Chicago Ave - Praxair	Flowgate	43	733	690	31	513	482	0%	8%	8%	0%	6%	6%
15	Northwest Tap - Purdue	Flowgate	1,304	702	(602)	1,170	612	(558)	15%	8%	(7%)	13%	7%	(6%)
16	Berwick - Koonsville	Line	1,690	608	(1,082)	1	0		19%	7%	(12%)	0%	0%	(0%)
17	Cedar Grove Sub - Williams	Line	1,174	553	(621)	582	175	(407)	13%	6%	(7%)	7%	2%	(5%)
18	Howard - Melmore	Line	0	749	749	0	211	211	0%	9%	9%	0%	2%	2%
19	Easton - Emuni	Line	714	1,673	959	5	0	(5)	8%	19%	11%	0%	0%	(0%)
20	Graceton - Safe Harbor	Line	1,268	496	(772)	427	253	(174)	14%	6%	(9%)	5%	3%	(2%)
21	Mt. Vernon - West Salem	Flowgate	667	204	(463)	540	179	(361)	8%	2%	(5%)	6%	2%	(4%)
22	Cumberland - Juniata	Line	645	1,206	561	256	512	256	7%	14%	6%	3%	6%	3%
23	Prest - Tibb	Flowgate	1,129	1,589	460	995	1,341	346	13%	18%	5%	11%	15%	4%
24	Sayreville - Sayreville	Line	31	808	777	0	0	0	0%	9%	9%	0%	0%	0%
25	AP South	Interface	10	568	558	18	229	211	0%	6%	6%	0%	3%	2%

Top Constraints

Table 11-31 and Table 11-32 show the top constraints contributing to congestion costs by facility for 2022 and 2021.

The Nottingham Series Reactor is the largest contributor to congestion costs due to frequently binding since October 2021, with $283.4 million in total congestion costs and 11.3 percent of the total PJM congestion costs in 2022.The day-ahead congestion event hours of Nottingham Series Reactor increased from 2,068 in 2021 to 4,645 in 2022 and the real-time congestion event hours of Nottingham Series Reactor increased from 1,280 in 2021 to 3,066 in 2022 (Table 11-29.)

The Brambleton - Evergreen Mills Line was the second largest contributor to congestion costs in 2022, with $281.8 million in total congestion costs and 11.3 percent of the total PJM congestion costs in 2022. The constraints related to the Data Center Alley area of Northern Virginia comprised 25.8 percent of all PJM congestion costs in 2022.[30]

30 This is the sum of the shares of total congestion costs for all DOM constraints and AP South Interface in the top 25 except the Greys Point - Harmony Village Line.

Table 11-31 Top 25 constraints affecting congestion costs: 2022[31]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Nottingham	Other	PECO	$305.3	$16.2	$17.6	$306.7	$26.6	$34.6	($15.3)	($23.3)	$283.4	11.3%
2	Brambleton - Evergreen Mills	Line	DOM	$170.0	($159.8)	$8.5	$338.2	$23.8	$14.2	($66.0)	($56.4)	$281.8	11.3%
3	Cumberland - Juniata	Line	PPL	$22.9	($128.4)	$2.7	$154.0	$2.0	$3.6	($6.6)	($8.2)	$145.8	5.8%
4	AP South	Interface	500	$58.0	($70.6)	$5.6	$134.3	$0.3	$8.2	($12.9)	($20.8)	$113.5	4.5%
5	Beaumeade	Other	DOM	$98.8	($18.0)	$3.5	$120.2	$9.5	$7.6	($16.8)	($14.9)	$105.3	4.2%
6	Idylwood - Clark	Line	DOM	$19.5	($67.8)	$1.8	$89.1	$4.0	$0.8	($16.5)	($13.4)	$75.7	3.0%
7	Bedington - Black Oak	Interface	500	$30.3	($53.8)	$2.1	$86.2	($0.8)	$15.1	($7.0)	($23.0)	$63.1	2.5%
8	Conastone - Northwest	Line	BGE	$44.3	($13.0)	$3.2	$60.5	$1.2	$3.0	($1.6)	($3.4)	$57.1	2.3%
9	Ashburn - Cochran Mill	Line	DOM	$41.5	($17.0)	$1.1	$59.6	$5.1	$8.5	($4.6)	($8.0)	$51.6	2.1%
10	Dauphin - Juniata	Line	PPL	($19.6)	($66.9)	$2.3	$49.6	$0.0	$0.0	$0.0	$0.0	$49.6	2.0%
11	Maroa E - Goose Creek	Flowgate	MISO	($15.2)	($61.9)	($0.9)	$45.8	$0.3	($6.1)	($9.5)	($3.1)	$42.7	1.7%
12	Greys Point - Harmony Village	Line	DOM	$139.0	$79.5	$3.3	$62.8	($15.8)	$2.2	($3.5)	($21.5)	$41.3	1.7%
13	Coolspring - Milford	Line	DPL	$6.0	($33.4)	$0.6	$40.0	($5.5)	($3.6)	($1.2)	($3.1)	$36.9	1.5%
14	Lauschtown	Transformer	500	$13.9	($20.2)	$1.3	$35.5	($0.4)	$0.2	($0.3)	($0.9)	$34.5	1.4%
15	Prest - Tibb	Flowgate	MISO	($9.4)	($46.2)	$5.6	$42.3	$0.5	$3.4	($5.3)	($8.2)	$34.2	1.4%
16	Boonetown - South Reading	Line	MEC	$1.7	($31.5)	$1.0	$34.2	($0.3)	$0.2	($0.7)	($1.2)	$33.0	1.3%
17	Frackville - Siegfried	Line	PPL	$9.0	($22.5)	$0.9	$32.4	$0.0	$0.0	$0.0	$0.0	$32.4	1.3%
18	Bull Run - Clifton	Line	DOM	$20.7	($8.0)	$2.0	$30.7	$0.8	$0.1	($0.7)	($0.0)	$30.7	1.2%
19	Conastone	Transformer	500	$18.2	($12.2)	$0.1	$30.4	($0.5)	$2.4	($0.2)	($3.1)	$27.3	1.1%
20	Conastone - Peach Bottom	Line	500	$18.6	($1.9)	$1.6	$22.1	$1.7	($4.7)	($2.8)	$3.6	$25.7	1.0%
21	Allen - R.P. Mone	Line	AEP	($4.9)	($29.6)	$2.8	$27.5	($0.8)	($0.4)	($3.0)	($3.5)	$24.0	1.0%
22	Lenox - North Meshoppen	Line	PE	$7.9	($30.5)	$2.9	$41.4	($0.2)	$12.9	($6.1)	($19.2)	$22.2	0.9%
23	Harwood - Susquehanna	Line	PPL	$3.9	($17.9)	$0.7	$22.5	($0.2)	$0.4	($0.3)	($0.9)	$21.7	0.9%
24	Juniata	Transformer	500	$5.3	($15.4)	($0.2)	$20.6	$0.2	($0.9)	($0.4)	$0.7	$21.3	0.9%
25	Graceton - Safe Harbor	Line	BGE	$22.3	($0.4)	$1.1	$23.8	$1.5	$3.6	($0.9)	($3.1)	$20.7	0.8%
	Top 25 Total			$1,008.1	($831.1)	$71.2	$1,910.4	$52.8	$105.5	($182.3)	($234.9)	$1,675.5	67.0%
	All Other Constraints			$198.2	($841.0)	$75.6	$1,114.9	($30.3)	$85.5	($173.2)	($289.0)	$825.8	33.0%
	Total			$1,206.3	($1,672.1)	$146.8	$3,025.2	$22.5	$191.0	($355.4)	($523.9)	$2,501.3	100.0%

Table 11-32 Top 25 constraints affecting congestion costs: 2021[32]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Three Mile Island	Transformer	500	$37.2	($49.7)	$2.4	$89.2	($0.3)	($1.2)	($2.0)	($1.1)	$88.2	8.9%
2	Nottingham	Other	PECO	$75.5	$0.7	$6.1	$80.9	$4.8	$5.4	($2.8)	($3.4)	$77.5	7.8%
3	Cumberland - Juniata	Line	PPL	$6.7	($38.4)	$1.5	$46.6	($0.2)	($0.6)	($2.0)	($1.6)	$45.0	4.5%
4	Conastone	Transformer	500	$19.8	($17.0)	$1.0	$37.8	$0.5	$1.2	($0.6)	($1.4)	$36.4	3.7%
5	Brighton	Other	APS	$38.3	$1.7	$2.8	$39.4	$7.3	$8.7	($5.0)	($6.4)	$33.0	3.3%
6	Hope Creek - Silver Run	Line	PSEG	($0.7)	($33.2)	$0.3	$32.8	($1.1)	($0.9)	$0.1	($0.1)	$32.7	3.3%
7	Conastone - Northwest	Line	BGE	$19.9	($12.8)	$1.8	$34.6	$5.5	$6.0	($1.5)	($2.0)	$32.6	3.3%
8	East Lima - Haviland	Line	AEP	($58.4)	($94.7)	$2.8	$39.2	($1.1)	$4.0	($3.7)	($8.8)	$30.3	3.0%
9	Juniata	Transformer	500	$11.3	($24.5)	($0.3)	$35.5	($2.4)	$2.3	($0.5)	($5.2)	$30.3	3.0%
10	Pleasant View - Ashburn	Line	DOM	$29.8	$1.8	$0.7	$28.7	$0.8	$0.4	($1.1)	($0.7)	$28.0	2.8%
11	Graceton - Safe Harbor	Line	BGE	$25.4	$0.7	$2.2	$27.0	$1.4	$1.0	($0.9)	($0.4)	$26.5	2.7%
12	Brambleton - Evergreen Mills	Line	DOM	$9.2	($15.6)	$0.6	$25.4	$0.1	($0.2)	($0.7)	($0.4)	$25.0	2.5%
13	Prest - Tibb	Flowgate	MISO	($10.3)	($33.7)	$1.9	$25.3	$2.4	$2.9	($1.9)	($2.4)	$22.9	2.3%
14	Bagley - Raphael Road	Line	BGE	$18.9	($2.7)	$1.7	$23.4	$1.7	$2.2	($2.1)	($2.5)	$20.9	2.1%
15	Pleasant View	Transformer	DOM	$4.4	($18.6)	$0.5	$23.4	$1.3	$2.2	($2.3)	($3.2)	$20.3	2.0%
16	Northwest Tap - Purdue	Flowgate	MISO	($8.5)	($39.4)	($1.1)	$29.8	$1.4	$12.1	$0.4	($10.3)	$19.5	2.0%
17	Vienna	Transformer	DPL	$18.6	($6.8)	$0.6	$26.0	($10.6)	($3.2)	$0.5	($6.9)	$19.1	1.9%
18	Harwood - Susquehanna	Line	PPL	$3.7	($16.3)	$0.8	$20.9	($0.2)	$0.9	($0.9)	($2.0)	$18.8	1.9%
19	Lafayette	Flowgate	MISO	($4.0)	($17.6)	$0.0	$13.6	$0.5	$1.8	$0.4	($0.9)	$12.7	1.3%
20	Rappahanock - White Stone	Line	DOM	$33.2	$18.7	$1.6	$16.0	($2.7)	($0.7)	($1.5)	($3.5)	$12.5	1.3%
21	Gardners - Texas Eastern	Line	MEC	($1.0)	($13.9)	$0.2	$13.2	($1.6)	$0.5	($0.2)	($2.3)	$10.9	1.1%
22	Bagley - Graceton	Line	BGE	$8.7	($1.6)	$0.5	$10.7	$0.3	$0.6	($0.0)	($0.4)	$10.4	1.0%
23	Ashburn - Cochran Mill	Line	DOM	$8.6	($0.7)	$0.5	$9.9	$0.2	$0.3	($0.4)	($0.4)	$9.4	0.9%
24	Sandburg	Flowgate	MISO	($10.0)	($25.4)	$1.8	$17.2	($0.6)	$4.9	($2.5)	($8.0)	$9.2	0.9%
25	Lauschtown	Transformer	500	$2.0	($5.8)	$0.1	$8.0	$0.1	($0.1)	($0.0)	$0.1	$8.1	0.8%
	Top 25 Total			$278.5	($444.7)	$31.1	$754.3	$7.4	$50.5	($31.1)	($74.2)	$680.1	68.3%
	All Other Constraints			$133.4	($302.3)	$36.2	$471.8	($27.7)	$59.4	($69.6)	($156.7)	$315.1	31.7%
	Total			$411.9	($747.0)	$67.3	$1,226.2	($20.3)	$110.0	($100.7)	($230.9)	$995.3	100.0%

Figure 11-9 shows the hourly total congestion costs of the top five constraints in 2022. Two of the top five constraints were in the DOM Zone as a result of increased load in the Data Center Alley area of Northern Virginia (The Brambleton - Evergreen Mills Line, the Cumberland – Juniata Line, the Beaumeade Circuit Breaker and the AP South Interface). The increased load in the DOM Zone resulted in the dispatch of more expensive generation units to control the affected constraints. The Brambleton - Evergreen Mills Line, the Cumberland – Juniata Line, and the Beaumeade

31 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.
32 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.

Circuit Breaker also had 20 hours of transmission constraint penalty factors in the day-ahead market which added to the high congestion costs.

Figure 11-9 Top five constraints affecting total congestion costs: 2022

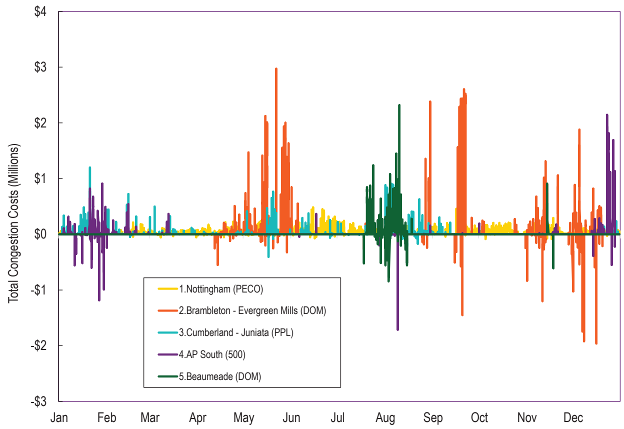


Figure 11-10 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in 2022.

Figure 11-10 Location of the top 10 constraints by total congestion costs: 2022

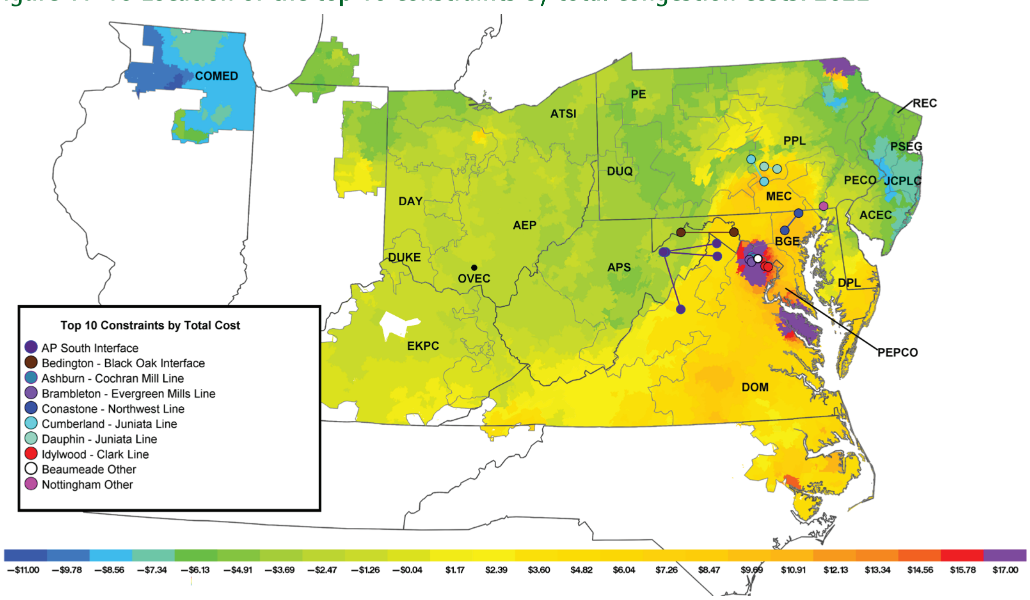


Figure 11-11 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in 2022.

Figure 11-11 Location of top 10 constraints by balancing congestion costs: 2022

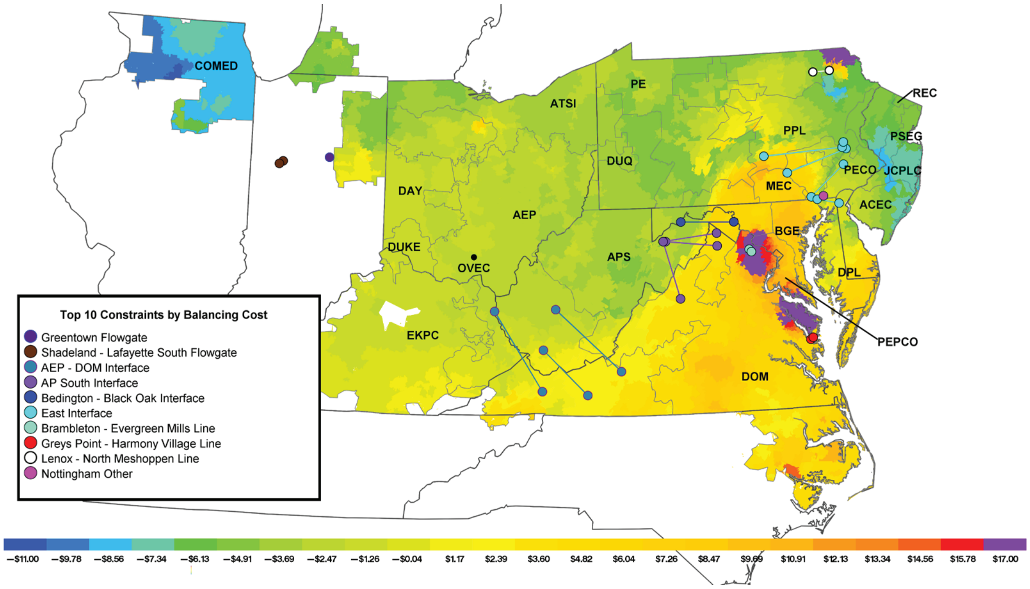
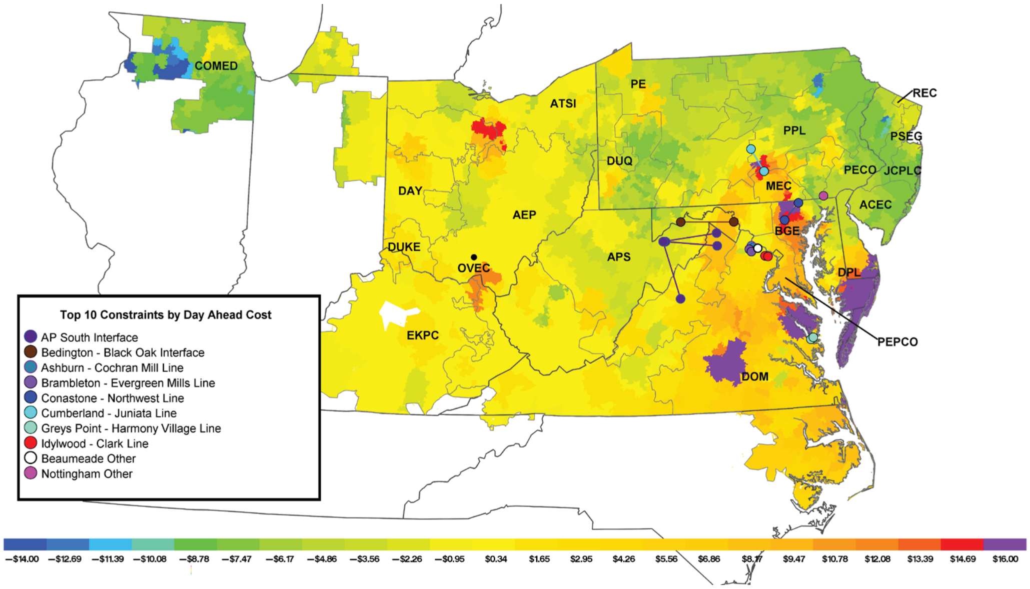


Figure 11-12 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in 2022.

Figure 11-12 Location of the top 10 constraints by day-ahead congestion costs: 2022



Comparing Figure 11-11 (Location of the top 10 constraints by balancing congestion costs) and Figure 11-12 (location of the top 10 constraints by day ahead congestion costs) shows the significant differences between the day ahead and real time market.

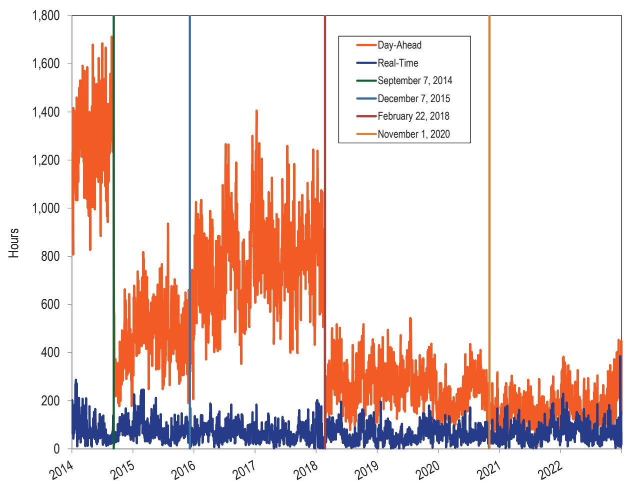
Congestion Event Summary: Impact of Changes in UTC Volumes

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.[33]

In 2022, the average hourly cleared UTC MW increased by 87.8 percent, compared to 2021. Day-ahead congestion event hours increased by 29.0 percent from 56,617 congestion event hours in 2021 to 73,031 congestion event hours in 2022 (Table 11-25).

Figure 11-13 shows the daily day-ahead and real-time congestion event hours for 2014 through 2022.

Figure 11-13 Daily congestion event hours: 2014 through 2022



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). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, 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 implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection 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.[34] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[35] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation

33 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

34 PJM Operating Agreement Schedule 1 §3.7.
35 *Id.*

of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load weighted reference bus is the marginal cost of energy at the load weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted average MLMP across all load buses, calculated relative to that reference bus is positive. 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.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

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 marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[36]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and

36 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 89 (Nov. 1, 2022).

the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.

- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP 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 Implicit Load MLMP Charges.** Balancing implicit load MLMP charges 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 implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP 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 implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges 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 plus export ratio basis.[37]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for 2022 was $1,918.0 million, which was comprised of implicit withdrawal MLMP charges of $165.2 million minus implicit injection MLMP credits of -$1,803.5 million plus explicit loss charges of -$50.6 million plus inadvertent loss charges of $0.0 million (Table 11-34).

Monthly marginal loss costs in 2022 ranged from $85.7 million in March to $257.4 million in August. Total marginal loss surplus increased in 2022 by $303.6 million or 91.9 percent from $330.4 million in 2021 to $633.9 million in 2022.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for 2008 through 2022.

Table 11-33 Total loss component costs (Dollars (Millions)): 2008 through 2022[38 39]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,300	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,770	4.7%
2011	$1,380	(15.6%)	$35,890	3.8%
2012	$982	(28.8%)	$29,180	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%
2019	$642	(33.1%)	$41,680	1.5%
2020	$479	(25.5%)	$36,280	1.3%
2021	$955	99.5%	$54,130	1.8%
2022	$1,918	100.9%	$86,220	2.2%

Table 11-34 shows PJM total marginal loss costs by accounting category for 2008 through 2022. Table 11-35 shows PJM total marginal loss costs by accounting category by market for 2008 through 2022.

37 PJM Operating Agreement Schedule 1 §3.7.
38 The loss costs include net inadvertent charges.
39 In Table 11-33, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-34 Total marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2022

	Marginal Loss Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($42.2)	($1,014.3)	($11.9)	$0.0	$960.1
2019	($44.7)	($703.4)	($16.6)	($0.0)	$642.0
2020	($25.9)	($518.2)	($13.7)	$0.0	$478.5
2021	($2.7)	($966.3)	($8.9)	$0.0	$954.8
2022	$165.2	($1,803.5)	($50.6)	($0.0)	$1,918.0

Table 11-35 Total marginal loss costs by market (Dollars (Millions)): 2008 through 2022

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.0)	$0.0	$960.1
2019	($47.1)	($700.3)	$43.3	$696.5	$2.4	($3.1)	($60.0)	($54.5)	($0.0)	$642.0
2020	($27.6)	($517.4)	$36.5	$526.3	$1.7	($0.8)	($50.3)	($47.7)	$0.0	$478.5
2021	($4.2)	($958.4)	$33.7	$987.9	$1.5	($7.9)	($42.5)	($33.1)	$0.0	$954.8
2022	$167.1	($1,786.0)	$99.1	$2,052.3	($1.9)	($17.5)	($149.8)	($134.2)	($0.0)	$1,918.0

Table 11-36 and Table 11-37 show PJM accounting based total loss costs for each transaction type in 2022 and 2021.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In 2022, DECs paid $1.9 million in MLMP charges in the day-ahead market, paid $7.8 million in MLMP in the balancing energy market and paid $9.7 million in total MLMP charges. In 2022, INCs paid $42.0 million in MLMP charges in the day-ahead market, were paid $60.2 million in MLMP credits in the balancing energy market and were paid $18.2 million in total MLMP credits. In 2022, up to congestion paid $101.7 million in MLMP charges in the day-ahead market, were paid $148.8 million in MLMP credits in the balancing energy market and received $47.1 million in total MLMP credits.

Table 11-36 Total loss costs by transaction type (Dollars (Millions)): 2022

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$1.9	$0.0	$0.0	$1.9	$7.8	$0.0	$0.0	$7.8	$0.0	$9.7
Demand	$127.2	$0.0	$0.0	$127.2	$25.7	$0.0	$0.0	$25.7	$0.0	$152.9
Demand Response	$0.1	$0.0	$0.0	$0.1	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.1)
Explicit Congestion and Loss Only	$0.0	$0.0	($3.4)	($3.4)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($3.4)
Export	($37.1)	$0.0	($0.4)	($37.5)	($22.9)	$0.0	($0.5)	($23.4)	$0.0	($60.9)
Generation	$0.0	($1,813.5)	$0.0	$1,813.5	$0.0	($32.5)	$0.0	$32.5	$0.0	$1,846.0
Import	$0.0	($6.8)	$0.0	$6.8	$0.0	($32.9)	$0.0	$32.9	$0.0	$39.7
INC	$0.0	($42.0)	$0.0	$42.0	$0.0	$60.2	$0.0	($60.2)	$0.0	($18.2)
Internal Bilateral	$75.1	$76.3	$1.3	($0.0)	($12.3)	($12.3)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$101.7	$101.7	$0.0	$0.0	($148.8)	($148.8)	$0.0	($47.1)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.4)
Total	$167.1	($1,786.0)	$99.1	$2,052.3	($1.9)	($17.5)	($149.8)	($134.2)	$0.0	$1,918.0

Table 11-37 Total loss costs by transaction type (Dollars (Millions)): 2021

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($1.0)	$0.0	$0.0	($1.0)	$4.5	$0.0	$0.0	$4.5	$0.0	$3.4
Demand	$16.2	$0.0	$0.0	$16.2	$7.8	$0.0	$0.0	$7.8	$0.0	$24.0
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	($0.9)	($0.9)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($1.0)
Export	($21.0)	$0.0	($0.1)	($21.1)	($9.1)	$0.0	$0.6	($8.5)	$0.0	($29.6)
Generation	$0.0	($945.3)	$0.0	$945.3	$0.0	($19.1)	$0.0	$19.1	$0.0	$964.3
Import	$0.0	($1.4)	$0.0	$1.4	$0.0	($4.3)	$0.0	$4.3	$0.0	$5.7
INC	$0.0	($13.8)	$0.0	$13.8	$0.0	$17.0	$0.0	($17.0)	$0.0	($3.2)
Internal Bilateral	$1.6	$2.1	$0.5	$0.0	($1.6)	($1.6)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$34.3	$34.3	$0.0	$0.0	($43.0)	($43.0)	$0.0	($8.8)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)
Total	($4.2)	($958.4)	$33.7	$987.9	$1.5	($7.9)	($42.5)	($33.1)	$0.0	$954.8

Table 11-38 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in 2022. Total MLMP charges to generation increased by $3.3 million, and total MLMP charges to demand increased by $2.9 million from the dispatch run to the pricing run. The total MLMP charges to DECs increased by $0.3 million, the total MLMP credits to INCs increased by $3.1 million and the total CLMP credits to UTCs increased by $8.9 million from the dispatch run to the pricing run.

Table 11-38 Total loss costs by dispatch and pricing run (Dollars (Millions)): 2022

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$1.9	$7.6	$9.4	$1.9	$7.8	$9.7	($0.0)	$0.3	$0.3
Demand	$126.9	$23.1	$150.0	$127.2	$25.7	$152.9	$0.3	$2.6	$2.9
Demand Response	$0.1	($0.2)	($0.0)	$0.1	($0.2)	($0.1)	$0.0	($0.0)	($0.0)
Explicit Congestion and Loss Only	($3.4)	($0.0)	($3.4)	($3.4)	($0.0)	($3.4)	($0.0)	$0.0	($0.0)
Export	($37.6)	($22.1)	($59.6)	($37.5)	($23.4)	($60.9)	$0.0	($1.3)	($1.3)
Generation	$1,811.5	$31.2	$1,842.7	$1,813.5	$32.5	$1,846.0	$2.1	$1.3	$3.3
Import	$6.8	$31.2	$38.0	$6.8	$32.9	$39.7	$0.0	$1.7	$1.7
INC	$42.1	($57.2)	($15.1)	$42.0	($60.2)	($18.2)	($0.0)	($3.0)	($3.1)
Internal Bilateral	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)
Up to Congestion	$101.7	($140.0)	($38.3)	$101.7	($148.8)	($47.1)	($0.0)	($8.8)	($8.9)
Wheel In	$0.0	($0.4)	($0.4)	$0.0	($0.4)	($0.4)	$0.0	($0.0)	($0.0)
Total	$2,050.0	($126.9)	$1,923.1	$2,052.3	($134.2)	$1,918.0	$2.3	($7.4)	($5.1)

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for 2021 and 2022.

Table 11-39 Monthly marginal loss costs (Millions): 2021 and 2022

	Marginal Loss Costs (Millions)							
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$62.0	($2.1)	($0.0)	$59.9	$213.0	($18.4)	$0.0	$194.6
Feb	$107.7	($5.1)	$0.0	$102.7	$120.9	($8.1)	$0.0	$112.8
Mar	$50.8	($3.7)	$0.0	$47.2	$91.5	($5.8)	($0.0)	$85.7
Apr	$44.4	($1.8)	($0.0)	$42.5	$103.6	($4.1)	($0.0)	$99.5
May	$53.4	($3.0)	$0.0	$50.4	$155.8	($8.4)	($0.0)	$147.4
Jun	$76.1	($2.8)	$0.0	$73.3	$188.0	($10.1)	($0.0)	$177.9
Jul	$98.5	($2.5)	$0.0	$96.1	$253.2	($14.7)	$0.0	$238.5
Aug	$113.6	($0.8)	$0.0	$112.8	$276.9	($19.5)	($0.0)	$257.4
Sep	$88.9	($3.5)	$0.0	$85.4	$170.7	($12.5)	($0.0)	$158.2
Oct	$98.6	($2.7)	($0.0)	$95.9	$106.9	($6.9)	($0.0)	$100.1
Nov	$116.5	($4.0)	$0.0	$112.4	$114.2	($8.4)	($0.0)	$105.8
Dec	$77.4	($1.2)	($0.0)	$76.3	$257.6	($17.5)	($0.0)	$240.1
Total	$987.9	($33.1)	$0.0	$954.8	$2,052.3	($134.2)	($0.0)	$1,918.0

Figure 11-14 shows PJM monthly marginal loss costs for 2008 through 2022.

Figure 11-14 Monthly marginal loss cost (Dollars (Millions)): 2008 through 2022

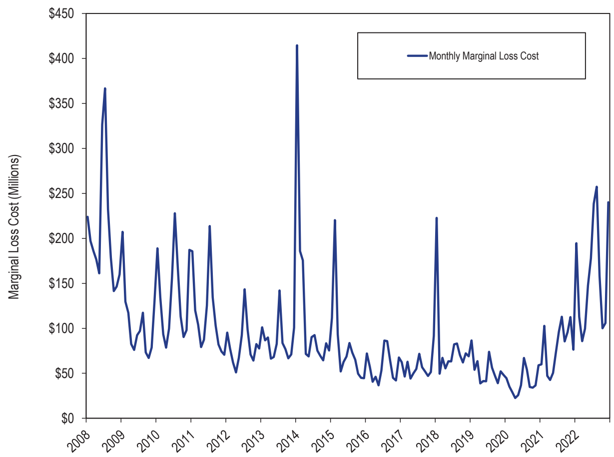


Table 11-40 shows the monthly total loss charges for each virtual transaction type for 2021 and 2022. In 2022, 84.7 percent of the total credits to virtuals went to UTCs, compared to 102.6 percent in 2021.

Table 11-40 Monthly loss charges by virtual transaction type (Dollars (Millions)): 2021 and 2022

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$0.3	($0.1)	$0.2	$0.8	($1.1)	($0.3)	$2.2	($2.6)	($0.4)	($0.5)
	Feb	$1.1	($0.7)	$0.4	$0.8	($0.9)	($0.1)	$4.5	($4.7)	($0.2)	$0.1
	Mar	$0.2	$0.2	$0.4	$1.2	($1.3)	($0.2)	$2.5	($3.2)	($0.7)	($0.5)
	Apr	($0.3)	$0.3	$0.1	$1.2	($1.1)	$0.0	$1.8	($2.2)	($0.4)	($0.2)
	May	($0.0)	$0.1	$0.0	$1.0	($1.1)	($0.1)	$2.5	($3.2)	($0.7)	($0.7)
	Jun	$0.1	$0.1	$0.2	$0.7	($1.0)	($0.2)	$3.2	($4.2)	($1.1)	($1.0)
	Jul	($0.1)	$0.5	$0.5	$0.8	($0.9)	($0.1)	$3.6	($3.8)	($0.2)	$0.1
	Aug	($0.4)	$1.2	$0.8	$0.6	($1.1)	($0.4)	$2.5	($3.1)	($0.6)	($0.3)
	Sep	($0.1)	$0.3	$0.2	$1.1	($1.7)	($0.5)	$2.5	($4.5)	($2.0)	($2.3)
	Oct	($1.1)	$0.9	($0.2)	$1.6	($1.9)	($0.3)	$2.5	($3.4)	($1.0)	($1.4)
	Nov	($0.6)	$0.8	$0.2	$2.9	($3.5)	($0.6)	$4.6	($5.4)	($0.8)	($1.1)
	Dec	($0.3)	$0.8	$0.5	$1.0	($1.5)	($0.5)	$1.9	($2.7)	($0.8)	($0.7)
	Total	($1.0)	$4.5	$3.4	$13.8	($17.0)	($3.2)	$34.3	($43.0)	($8.8)	($8.5)
2022	Jan	$6.8	($5.6)	$1.2	$2.9	($4.9)	($2.0)	$7.2	($10.4)	($3.1)	($3.9)
	Feb	$5.1	($1.9)	$3.3	$1.7	($3.0)	($1.3)	$5.7	($7.8)	($2.1)	($0.1)
	Mar	$0.3	$0.6	$0.9	$2.5	($3.5)	($1.0)	$2.8	($5.6)	($2.8)	($3.0)
	Apr	($0.9)	$1.2	$0.3	$3.4	($4.3)	($0.9)	$4.0	($5.7)	($1.7)	($2.3)
	May	($1.6)	$1.8	$0.2	$4.5	($4.7)	($0.2)	$7.6	($9.0)	($1.4)	($1.4)
	Jun	($2.3)	$2.6	$0.3	$2.9	($4.9)	($1.9)	$8.5	($14.2)	($5.7)	($7.3)
	Jul	($1.3)	$2.4	$1.1	$3.7	($5.1)	($1.4)	$10.3	($14.8)	($4.5)	($4.8)
	Aug	($0.8)	$2.2	$1.5	$3.6	($6.1)	($2.5)	$12.6	($20.0)	($7.4)	($8.5)
	Sep	($1.6)	$2.2	$0.7	$3.0	($3.5)	($0.6)	$9.0	($12.1)	($3.1)	($3.0)
	Oct	($0.8)	$1.4	$0.6	$3.6	($3.7)	($0.1)	$5.6	($7.0)	($1.4)	($1.0)
	Nov	($1.1)	$1.2	$0.1	$5.1	($5.1)	($0.1)	$9.2	($9.6)	($0.4)	($0.3)
	Dec	($0.0)	($0.4)	($0.4)	$5.1	($11.3)	($6.2)	$19.1	($32.5)	($13.4)	($20.0)
	Total	$1.9	$7.8	$9.7	$42.0	($60.2)	($18.2)	$101.7	($148.8)	($47.1)	($55.7)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges 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 injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system 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 11-41 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for 2008 through 2022. The total marginal loss surplus increased by $303.6 million or 91.9 percent in 2022 from 2021.

Table 11-41 Marginal loss surplus (Dollars (Millions)): 2008 through 2022[40]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustments			
	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	($0.0)	($0.4)	($0.1)	$639.4
2010	($797.9)	$1,634.8	$0.0	($0.7)	($0.0)	$837.7
2011	($793.8)	$1,379.5	$0.1	$0.7	($0.0)	$585.2
2012	($593.0)	$981.7	$0.1	($1.0)	$0.1	$389.6
2013	($687.6)	$1,035.3	$0.0	$2.0	($0.0)	$345.7
2014	($977.7)	$1,466.1	$0.0	($0.0)	($0.0)	$488.4
2015	($627.4)	$968.7	($0.0)	$6.3	$0.1	$335.0
2016	($466.3)	$696.5	($0.0)	$5.1	($0.1)	$225.2
2017	($475.2)	$690.8	($0.0)	$3.2	($0.2)	$212.6
2018	($636.7)	$960.1	$0.0	$1.1	($0.1)	$322.4
2019	($435.2)	$642.0	($0.0)	$3.2	($0.1)	$203.7
2020	($317.4)	$478.5	($0.0)	$1.7	($0.1)	$159.6
2021	($623.2)	$954.8	($0.0)	$1.3	($0.1)	$330.4
2022	($1,282.1)	$1,918.0	($0.0)	$2.0	($0.1)	$633.9

System Energy Costs

Energy Accounting

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

Total System Energy Costs

The total system energy cost for 2022 was -$1,282.1 million, which was comprised of implicit withdrawal energy charges of $83,241.0 million, implicit injection energy credits of $84,502.1 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$21.0 million. The monthly system energy costs for 2022 ranged from -$168.6 million in August to -$60.0 million in March.

Table 11-42 shows total system energy costs and total PJM billing, for 2008 through 2022.

Table 11-42 Total system energy costs (Dollars (Millions)): 2008 through 2022[41 42]

	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,300	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,770	(2.3%)
2011	($794)	(0.5%)	$35,890	(2.2%)
2012	($593)	(25.3%)	$29,180	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)
2019	($435)	(31.6%)	$41,680	(1.0%)
2020	($317)	(27.1%)	$36,280	(0.9%)
2021	($623)	96.4%	$54,130	(1.2%)
2022	($1,282)	105.7%	$86,220	(1.5%)

40 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.
41 The system energy costs include net inadvertent charges.
42 In Table 11-42, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

System energy costs for 2008 through 2022 are shown in Table 11-43 and Table 11-44. Table 11-43 shows PJM system energy costs by accounting category and Table 11-44 shows PJM system energy costs by market category.

Table 11-43 Total system energy costs by accounting category (Dollars (Millions)): 2008 through 2022

	System Energy Costs (Millions)				
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,805.9	$44,447.2	$0.0	$4.6	($636.7)
2019	$30,647.4	$31,081.1	$0.0	($1.5)	($435.2)
2020	$23,400.9	$23,720.8	$0.0	$2.5	($317.4)
2021	$42,312.4	$42,938.3	$0.0	$2.7	($623.2)
2022	$83,241.0	$84,502.1	$0.0	($21.0)	($1,282.1)

Table 11-44 Total system energy costs by market (Dollars (Millions)): 2008 through 2022

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,948.7	$44,659.7	$0.0	($711.0)	($142.9)	($212.6)	$0.0	$69.7	$4.6	($636.7)
2019	$31,034.3	$31,562.9	$0.0	($528.6)	($386.9)	($481.8)	$0.0	$94.9	($1.5)	($435.2)
2020	$23,581.5	$23,983.0	$0.0	($401.4)	($180.6)	($262.2)	$0.0	$81.6	$2.5	($317.4)
2021	$42,431.6	$43,109.9	$0.0	($678.2)	($119.3)	($171.5)	$0.0	$52.3	$2.7	($623.2)
2022	$83,732.0	$85,218.2	$0.0	($1,486.2)	($491.1)	($716.1)	$0.0	$225.0	($21.0)	($1,282.1)

Table 11-45 and Table 11-46 show the total system energy costs for each transaction type in 2022 and 2021. In 2022, generation was paid $62,109.9 million and demand paid $58,920.8 million in net energy payment. In 2021, generation was paid $32,198.2 million and demand paid $30,161.9 million in net energy payment.

Table 11-45 Total system energy costs by transaction type (Dollars (Millions)): 2022

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$3,277.1	$0.0	$0.0	$3,277.1	($3,467.5)	$0.0	$0.0	($3,467.5)	($190.4)
Demand	$57,490.7	$0.0	$0.0	$57,490.7	$1,430.1	$0.0	$0.0	$1,430.1	$58,920.8
Demand Response	($10.5)	$0.0	$0.0	($10.5)	$12.3	$0.0	$0.0	$12.3	$1.8
Export	$2,098.0	$0.0	$0.0	$2,098.0	$1,203.8	$0.0	$0.0	$1,203.8	$3,301.8
Generation	$0.0	$61,946.6	$0.0	($61,946.6)	$0.0	$163.3	$0.0	($163.3)	($62,109.9)
Import	$0.0	$217.6	$0.0	($217.6)	$0.0	$1,043.5	$0.0	($1,043.5)	($1,261.1)
INC	$0.0	$2,177.3	$0.0	($2,177.3)	$0.0	($2,253.2)	$0.0	$2,253.2	$75.9
Internal Bilateral	$20,876.7	$20,876.7	$0.0	($0.0)	$299.7	$299.7	$0.0	$0.0	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$30.7	$0.0	($30.7)	($30.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$30.7	$0.0	$0.0	$30.7	$30.7
Total	$83,732.0	$85,218.2	$0.0	($1,486.2)	($491.1)	($716.1)	$0.0	$225.0	($1,261.2)

Table 11-46 Total system energy costs by transaction type by (Dollars (Millions)): 2021

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$1,518.4	$0.0	$0.0	$1,518.4	($1,544.8)	$0.0	$0.0	($1,544.8)	($26.4)
Demand	$29,593.8	$0.0	$0.0	$29,593.8	$568.1	$0.0	$0.0	$568.1	$30,161.9
Demand Response	($0.9)	$0.0	$0.0	($0.9)	$0.9	$0.0	$0.0	$0.9	($0.0)
Export	$1,046.1	$0.0	$0.0	$1,046.1	$684.7	$0.0	$0.0	$684.7	$1,730.8
Generation	$0.0	$32,003.9	$0.0	($32,003.9)	$0.0	$194.3	$0.0	($194.3)	($32,198.2)
Import	$0.0	$54.4	$0.0	($54.4)	$0.0	$247.6	$0.0	($247.6)	($301.9)
INC	$0.0	$777.3	$0.0	($777.3)	$0.0	($785.2)	$0.0	$785.2	$7.9
Internal Bilateral	$10,274.3	$10,274.3	$0.0	$0.0	$157.9	$157.9	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$13.9	$0.0	($13.9)	($13.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$13.9	$0.0	$0.0	$13.9	$13.9
Total	$42,431.6	$43,109.9	$0.0	($678.2)	($119.3)	($171.5)	$0.0	$52.3	($625.9)

Table 11-47 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in 2022. The system energy charges to demand increased $105.0 million, and the energy credits to generation increased $60.0 million from the dispatch run to the pricing run. The energy credits to DEC increased $163.5 million, the energy charges to INC increased $105.5 million from the dispatch run to the pricing run.

Table 11-47 Total system energy costs by dispatch and pricing run (Dollars (Millions)): 2022

	System Energy Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$3,272.4	($3,299.4)	($27.0)	$3,277.1	($3,467.5)	($190.4)	$4.7	($168.2)	($163.5)
Demand	$57,432.4	$1,383.4	$58,815.7	$57,490.7	$1,430.1	$58,920.8	$58.3	$46.7	$105.0
Demand Response	($10.4)	$11.6	$1.2	($10.5)	$12.3	$1.8	($0.0)	$0.6	$0.6
Export	$2,094.7	$1,151.7	$3,246.4	$2,098.0	$1,203.8	$3,301.8	$3.3	$52.1	$55.4
Generation	($61,879.5)	($170.4)	($62,049.9)	($61,946.6)	($163.3)	($62,109.9)	($67.1)	$7.1	($60.0)
Import	($217.7)	($1,004.2)	($1,221.9)	($217.6)	($1,043.5)	($1,261.1)	$0.1	($39.3)	($39.2)
INC	($2,176.9)	$2,147.3	($29.6)	($2,177.3)	$2,253.2	$75.9	($0.4)	$105.9	$105.5
Internal Bilateral	($0.0)	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0
Wheel In	$0.0	($29.7)	($29.7)	$0.0	($30.7)	($30.7)	$0.0	($1.0)	($1.0)
Wheel Out	$0.0	$29.7	$29.7	$0.0	$30.7	$30.7	$0.0	$1.0	$1.0
Total	($1,485.1)	$220.0	($1,265.1)	($1,486.2)	$225.0	($1,261.2)	($1.1)	$5.0	$3.9

Monthly System Energy Costs

Table 11-48 shows a monthly summary of system energy costs by market type for 2021 and 2022. Total balancing system energy costs in 2022 increased in every month except for February and March compared to 2021. Monthly total system energy costs in 2022 ranged from -$168.6 million in August to -$60.0 million in March.

Table 11-48 Monthly system energy costs (Dollars (Millions)): 2021 and 2022

	System Energy Costs (Millions)							
	2021				2022			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($42.7)	$5.0	($0.1)	($37.8)	($139.7)	$13.2	($0.1)	($126.5)
Feb	($73.5)	$9.8	$0.7	($63.0)	($74.7)	$0.5	($0.1)	($74.3)
Mar	($35.8)	$5.1	$0.0	($30.7)	($64.7)	$4.9	($0.3)	($60.0)
Apr	($30.4)	$2.1	($0.1)	($28.4)	($78.1)	$9.0	($1.1)	($70.2)
May	($37.8)	$4.6	$0.1	($33.1)	($114.4)	$15.7	($0.4)	($99.1)
Jun	($52.8)	$5.0	$0.3	($47.5)	($138.0)	$17.1	($0.7)	($121.6)
Jul	($65.3)	$4.6	$0.8	($59.9)	($177.8)	$22.4	$0.6	($154.9)
Aug	($75.6)	$1.1	$1.5	($73.0)	($201.6)	$34.1	($1.1)	($168.6)
Sep	($61.5)	$3.9	$0.3	($57.3)	($127.7)	$25.7	($1.9)	($103.9)
Oct	($68.8)	$5.8	($0.3)	($63.4)	($81.4)	$15.3	($1.0)	($67.1)
Nov	($79.6)	$2.5	($0.2)	($77.3)	($95.2)	$24.9	($1.3)	($71.6)
Dec	($54.4)	$2.8	($0.3)	($51.8)	($192.8)	$42.2	($13.7)	($164.3)
Total	($678.2)	$52.3	$2.7	($623.2)	($1,486.2)	$225.0	($21.0)	($1,282.1)

Figure 11-15 shows PJM monthly system energy costs for 2008 through 2022. 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 (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0. Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-15 Monthly system energy costs (Millions): 2008 through 2022

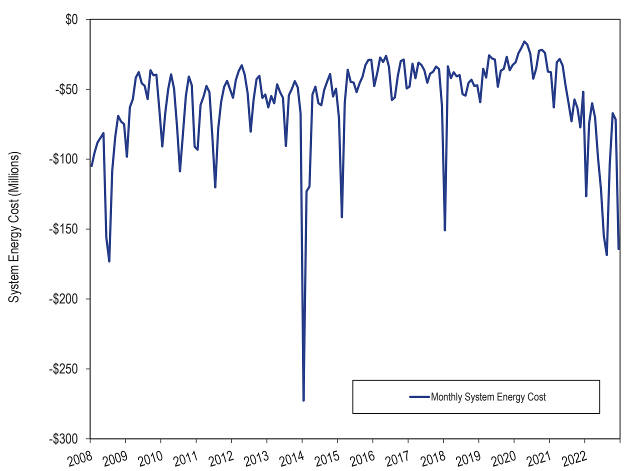


Table 11-49 shows the monthly total system energy costs for each virtual transaction type in 2022 and year of 2021. In 2022, DECs paid $3,277.1 million in energy charges compared to $1,518.4 million in 2021 in the day-ahead market, were paid $3,467.5 million in energy credits compared to $1,544.8 million in 2021 in the balancing energy market and were paid $190.4 million in total energy credits compared to $26.4 million in 2021. In 2022, INCs were paid $2,177.3 million in energy credits compared to $777.3 million in 2021 in the day-ahead market, paid $2,253.2 million in energy charges compared to $785.2 million in 2021 in the balancing market and paid $75.9 million in total energy charges compared to $7.9 million in 2021. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-49 Monthly energy charges by virtual transaction type (Dollars (Millions)): 2021 and 2022

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2021	Jan	$76.5	($76.2)	$0.3	($41.9)	$41.6	($0.3)	($0.0)
	Feb	$167.0	($157.6)	$9.4	($54.4)	$51.4	($3.0)	$6.5
	Mar	$83.8	($89.0)	($5.2)	($50.9)	$53.3	$2.4	($2.8)
	Apr	$73.2	($70.5)	$2.7	($62.3)	$60.6	($1.7)	$1.0
	May	$81.7	($81.3)	$0.5	($52.7)	$52.5	($0.2)	$0.2
	Jun	$123.2	($127.6)	($4.4)	($46.1)	$46.5	$0.4	($4.0)
	Jul	$117.8	($113.7)	$4.1	($67.8)	$64.9	($2.9)	$1.3
	Aug	$145.0	($154.3)	($9.3)	($65.3)	$68.8	$3.5	($5.8)
	Sep	$142.0	($153.1)	($11.1)	($70.9)	$75.7	$4.8	($6.3)
	Oct	$179.4	($180.4)	($1.0)	($87.0)	$87.5	$0.5	($0.5)
	Nov	$175.3	($180.3)	($5.1)	($114.1)	$116.3	$2.3	($2.8)
	Dec	$153.5	($160.9)	($7.4)	($64.0)	$66.0	$2.0	($5.4)
	Total	$1,518.4	($1,544.8)	($26.4)	($777.3)	$785.2	$7.9	($18.5)
2022	Jan	$312.1	($344.7)	($32.5)	($133.4)	$147.1	$13.7	($18.9)
	Feb	$207.9	($196.5)	$11.4	($119.5)	$111.8	($7.6)	$3.7
	Mar	$193.0	($183.9)	$9.1	($133.1)	$128.2	($4.9)	$4.2
	Apr	$180.0	($177.9)	$2.1	($179.0)	$177.1	($1.9)	$0.2
	May	$318.1	($319.0)	($0.9)	($211.9)	$211.1	($0.8)	($1.7)
	Jun	$316.0	($344.9)	($28.9)	($215.9)	$232.6	$16.7	($12.2)
	Jul	$317.4	($306.8)	$10.6	($218.4)	$209.2	($9.2)	$1.4
	Aug	$380.9	($403.6)	($22.7)	($236.1)	$253.6	$17.5	($5.2)
	Sep	$369.1	($348.0)	$21.1	($191.6)	$180.8	($10.8)	$10.3
	Oct	$211.9	($204.0)	$7.9	($154.7)	$147.3	($7.3)	$0.6
	Nov	$180.8	($172.3)	$8.6	($178.8)	$173.1	($5.8)	$2.8
	Dec	$289.8	($465.9)	($176.1)	($204.9)	$281.3	$76.4	($99.7)
	Total	$3,277.1	($3,467.5)	($190.4)	($2,177.3)	$2,253.2	$75.9	($114.5)