Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by operating segment. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

1 Losses occur when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

4 Demand response payments are addressed in the *2022 State of the Market Report for PJM*, Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits increased by $111.5 million, or 62.5 percent, in 2022 compared to 2021, from $178.4 million to $289.9 million.
- **Types of energy uplift credits.** In 2022, total energy uplift credits included $58.8 million in day-ahead generator credits, $181.6 million in balancing generator credits, $39.8 million in lost opportunity cost credits, and $3.2 million in local constraint control credits. Dispatch differential lost opportunity credits, which are a subset of balancing generator credits, were implemented as part of fast start pricing on September 1, 2021, and were $4.5 million in 2022. Regulation revenues should be included as an offset to uplift, but are not currently included.
- **Types of units.** In 2022, coal units received 48.0 percent of day-ahead generator credits, and combustion turbines received 75.2 percent of balancing generator credits and 86.9 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 65.3 percent of dispatch differential lost opportunity credits.
- **Day-ahead unit commitment for reliability.** In 2022, 0.3 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 56.8 percent received energy uplift payments.
- **Concentration of energy uplift credits.** In 2022, the top 10 units receiving energy uplift credits received 27.0 percent of all credits and the top 10 organizations received 70.7 percent of all credits. The HHI for day-ahead operating reserves was 8580, the HHI for balancing generator credits was 2329 and the HHI for lost opportunity cost was 5053, all of which are classified as highly concentrated.
- **Lost opportunity cost credits.** Lost opportunity cost credits increased by $9.6 million, or 32.0 percent, in 2022, compared to 2021, from $30.2 million to $39.8 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 84.4 percent of the $39.8 million.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $15.1 million, of which PJM has resettled only $1.5 million, or 9.7 percent.
- **Daily uplift.** In 2022, balancing operating reserve charges would have been $41.8 million or 23.0 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.
- **CT uplift exemption.** The rule that allowed CTs to be paid uplift regardless of how well they followed dispatch was terminated on November 1, 2022. Starting November 1, 2022, CTs are paid uplift if necessary to cover costs based on the lower of actual or desired output (as calculated by PJM based on the dispatch signal), like all other unit types.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges (equal to total energy uplift credits) increased by $111.5 million, or 62.5 percent, in 2022 compared to 2021, from $178.4 million to $289.9 million.
- **Types of Energy Uplift Charges.** In 2022, total uplift charges included $58.8 million in day-ahead operating reserve charges, $229.1 million in balancing operating reserve charges, $1.5 million in reactive services charges, and $0.5 million in black start services.
- **UTC Uplift.** Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges on a basis equivalent to a decrement bid (DEC) at the sink point of the UTC.[5]
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.062 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.115 per MWh. Deviations paid $0.533 per MWh in the Eastern Region.

5 See 172 FERC ¶ 61,046 (2020).

- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.0062 per MWh in the Western Region. Real-time load and exports paid $0.092 per MWh. Deviations paid $0.409 per MWh in the Western Region.

Geography of Charges and Credits

- In 2022, 87.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by MW at control zones, 5.3 percent by MW at hubs and aggregates, and 8.0 percent by MW at interchange interfaces.
- In 2022, generators in the Eastern Region received 52.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2022, generators in the Western Region received 45.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In 2022, external pseudo tied generators received 2.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels

their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[6]
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch in order to receive uplift. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Adopted.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[7] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[8] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. But that rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

7 See 173 FERC ¶ 61,244 (2020).

8 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[9] The uplift payments for UTCs began on November 1, 2020. The MMU has had a longstanding recommendation that UTCs be required to pay uplift on both the injection and withdrawal sides.[10]

On November 1, 2022, the longstanding rule which exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated.[11] Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch. As a result of the rule, CTs had no incentive to follow PJM dispatch signals and received excessive uplift credits.

The rule change is expected to reduce balancing generator reserve credits paid to combustion turbines and diesel engines. The rule change is expected to have no impact on lost opportunity cost credits, dispatch differential lost opportunity cost credits, reactive service credits, and black start credits, despite CTs also receiving a large share of those credit categories. No is expected to these categories because the calculation for these credit categories is not based on distinguishing the PJM calculated desired MW from the actual generation.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $15.1 million of incorrect uplift credits of which PJM has resettled only $1.5 million or 9.8 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

9 See 172 FERC ¶ 61,046 (2020).

10 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

11 See PJM "Manual 28: Operating Reserve Accounting," Rev. 88 (Oct. 1, 2022).

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category in 2021 and 2022.[12] In 2022, energy uplift credits increased by $111.5 million or 62.5 percent compared to 2021.

The dispatch differential lost opportunity cost is a credit paid to resources that, in order to accommodate inflexible fast start resources, are dispatched down to an output below the level that is economic for them at the market prices that result from fast start pricing. Fast start pricing was introduced on September 1, 2021, and with it the dispatch differential lost opportunity cost credit.[13]

Table 4-1 Energy uplift credits by category: 2021 and 2022[14 15]

Category	Type	2021 Credits (Millions)	2022 Credits (Millions)	Change	Percent Change	2021 Share	2022 Share
Day-Ahead	Generators	$13.7	$58.8	$45.1	330.3%	7.7%	20.3%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$127.7	$181.6	$53.9	42.2%	71.6%	62.7%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$4.8	$3.2	($1.7)	(34.3%)	2.7%	1.1%
	Lost Opportunity Cost	$30.2	$39.8	$9.6	32.0%	16.9%	13.7%
	Dispatch Differential Lost Opportunity Cost	$0.8	$4.5	NA	NA	NA	1.5%
Reactive Services	Day-Ahead	$0.3	$0.9	$0.6	230.3%	0.1%	0.3%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.2	$0.2	939.6%	0.0%	0.1%
	Reactive Services	$0.6	$0.4	($0.2)	(34.2%)	0.3%	0.1%
	Synchronous Condensing	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.3	$0.5	$0.2	50.3%	0.2%	0.2%
Total		$178.4	$289.9	$111.5	62.5%	100.0%	100.0%

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 09, 2023.

13 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures. The corrected value of the credits in 2021 is $0.5 million instead of the prior value of $0.8 million. The corrected value of the credits in 2022 is $3.2 million instead of the prior value of $4.5 million.

14 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

15 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationship. These tables show how the charges are allocated. The dispatch differential lost opportunity cost credit (DDLOC) is a new balancing credit that is required by fast start pricing, introduced on September 1, 2021. DDLOC is paid for by PJM members in proportion to their real-time load and exports for generator credits provided for reliability.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids & UTCs	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
			Balancing Local Constraint	Applicable Requesting Party	
Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	in RTO Region
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type in 2021 and 2022. A combination of factors led to increased uplift payments for day ahead operating reserves and balancing operating reserves including increased need for reliability generation by steam (coal and other fuels) units, and higher fuel prices.

The longstanding rule, which inexplicably exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated effective November 1, 2022. Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch. As a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines increased by $21.0 million or 13.7 percent in 2022 compared to 2021. In 2022, CTs received 83.5 percent of lost opportunity cost credits, an increase of $9.6 million or 32.0 percent compared to 2021. In 2022, 12.5 percent of total uplift credits received by CTs was received from December 23 through December 26, during Winter Storm Elliott (Elliott).

Uplift credits paid to steam coal units increased by $21.7 million or 160.7 percent during 2022 compared to 2021. In 2022, day-ahead uplift credits for reliability totaled $53.3 million, compared to $7.5 million in 2021. In 2022, day-ahead credits for reliability in the BGE, PPL, and PEPCO Zones made up 98.5 percent of total day-ahead credits for reliability. Reliability needs in the BGE and PEPCO Zones are the result of recurrent N-1-1 contingencies in the BGE and PEPCO Zones. A small number of coal units committed for reliability in the BGE and PPL Zones received 44.4 percent of day-ahead credits, and received 48.2 percent of the increase in day-ahead credits.

Uplift credits paid to other (gas or oil fired) steam units increased by $36.5 million or 1,100.1 percent during in 2022 compared to 2021. The increase in payments to gas or oil fired steam units was to a small number of units in the PEPCO, BGE, and PPL Zones. Gas or oil fired steam units were responsible for 34.1 percent of the increase in day-ahead credits during 2022 compared to 2021. In 2022, gas or oil fired steam units received $14.7 million, or 8.2 percent of total credits, compared to $2.5 million and 1.9 percent in 2021. In 2022, 49.6 percent of total uplift credits received by gas or oil fired steam units was received from December 23 through December 26, during Elliott.

Uplift credits paid to combined cycle units increased by $27.8 million or 471.0 percent during 2022 compared to 2021. In 2022, 58.3 percent of total uplift credits received by combined cycle units was received from December 23 through December 26, during Elliott.

In 2022, uplift credits to wind units were $2.5 million, up by 623.3 percent compared to 2021.

Table 4-4 Total energy uplift credits by unit type: 2021 and 2022[16] [17]

Unit Type	2021 Credits (Millions)	2022 Credits (Millions)	Change	Percent Change	2021 Share	2022 Share
Combined Cycle	$5.9	$33.7	$27.8	471.0%	3.3%	11.6%
Combustion Turbine	$153.5	$174.5	$21.0	13.7%	86.0%	60.2%
Diesel	$1.6	$3.1	$1.5	94.5%	0.9%	1.1%
Hydro	$0.3	$1.1	$0.8	299.6%	0.2%	0.4%
Nuclear	$0.0	$0.0	($0.0)	(93.9%)	0.0%	0.0%
Solar	$0.0	$0.1	$0.1	860.2%	0.0%	0.0%
Steam - Coal	$13.5	$35.2	$21.7	160.7%	7.6%	12.1%
Steam - Other	$3.3	$39.8	$36.5	1,100.1%	1.9%	13.7%
Wind	$0.3	$2.5	$2.1	623.3%	0.2%	0.8%
Total	$178.4	$289.9	$111.5	62.5%	100.0%	100.0%

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in 2022. The largest share of day-ahead credits, 48.0 percent, went to steam units because steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 75.2 percent of balancing credits and 83.5 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

16 Table 4-4 does not include balancing imports credits and load response credits in the total amounts.

17 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-5 Energy uplift credits by unit type: 2022[18]

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	10.3%	12.4%	0.0%	0.0%	9.3%	0.0%	0.0%	34.5%	29.1%
Combustion Turbine	1.5%	75.2%	0.0%	38.5%	83.5%	33.7%	0.0%	65.5%	36.2%
Diesel	0.0%	0.9%	0.0%	3.2%	3.4%	2.2%	0.0%	0.0%	0.4%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%
Steam - Coal	48.0%	3.0%	0.0%	0.0%	1.6%	32.1%	0.0%	0.0%	7.4%
Steam - Other	40.2%	8.5%	0.0%	0.0%	0.6%	32.0%	0.0%	0.0%	1.2%
Wind	0.0%	0.0%	0.0%	58.3%	1.3%	0.0%	0.0%	0.0%	1.6%
Total (Millions)	$58.8	$181.6	$0.0	$3.2	$39.8	$1.5	$0.0	$0.5	$4.5

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[19] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[20] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal.

Table 4-6 shows total day-ahead generation and day-ahead generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 103.0 percent from 2021 to 2022, from 1,371.7 GWh in 2021 to 2,784.5 GWh in 2022. The increase in day-ahead generation committed for reliability by PJM was the result of a need for reliability, primarily in the BGE and PEPCO Zones. PJM committed additional resources for reliability in the December 25 day-ahead market, resulting in a large increase in day-ahead uplift. The uplift received for day-ahead reliability on December 25, 2022, was 22.5 percent of annual day-ahead uplift credits.

Table 4-6 Day-ahead generation committed for reliability (GWh): 2021 through 2022

	2021			2022			Percent Change of PJM Day-Ahead Must Run Generation
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	
Jan	73,635	95	0.1%	81,373	0	0.0%	(100.0%)
Feb	71,354	13	0.0%	68,253	37	0.1%	191.6%
Mar	64,713	209	0.3%	66,579	4	0.0%	(98.2%)
Apr	57,137	13	0.0%	57,663	8	0.0%	(38.2%)
May	60,957	26	0.0%	63,309	389	0.6%	1,407.1%
Jun	72,987	126	0.2%	70,849	417	0.6%	231.9%
Jul	80,025	103	0.1%	81,815	594	0.7%	479.2%
Aug	81,744	86	0.1%	80,627	432	0.5%	403.9%
Sep	66,913	410	0.6%	67,871	378	0.6%	(7.7%)
Oct	61,610	15	0.0%	59,982	0	0.0%	(100.0%)
Nov	62,746	181	0.3%	62,046	49	0.1%	(73.0%)
Dec	69,036	96	0.1%	74,777	477	0.6%	395.2%
Total	822,857	1,372	0.2%	835,145	2,785	0.3%	103.0%

Pool scheduled units are units committed by PJM. Self scheduled units are self committed by the generation owner. Units committed for reliability by PJM are units that are committed in the day-ahead energy market, regardless of whether the offers are economic. Both types of units are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits

18 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures.

19 See OA Schedule 1 § 3.2.3(b).

20 See OA Schedule 1 § 3.2.3(a).

in 2022 were $58.8 million, of which $53.3 million or 90.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. There were no additional day-ahead operating reserves paid to units scheduled to provide reactive services. The top 10 units received $53.5 million or 91.0 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-7 shows the total day-ahead generation committed for reliability by PJM by category. In 2022, 56.8 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits. The remaining 43.2 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-7 Day-ahead generation committed for reliability by category (GWh): 2022

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	17.9	19.6	37.5
Feb	0.0	3.7	0.0	3.7
Mar	0.0	8.1	0.0	8.1
Apr	17.1	79.9	291.5	388.5
May	0.0	214.3	202.7	416.9
Jun	0.0	384.3	209.6	593.9
Jul	0.0	268.8	162.7	431.5
Aug	0.0	332.8	45.4	378.2
Sep	0.0	48.8	0.0	48.8
Oct	3.5	201.9	272.1	477.4
Nov	0.0	0.0	0.0	0.0
Dec	0.0	0.0	0.0	0.0
Total	20.6	1,560.4	1,203.6	2,784.5
Share	0.7%	56.0%	43.2%	100.0%

Balancing Operating Reserve Credits/ Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover their operating costs from market revenues. The term refers specifically to balancing operating reserves paid to generators, and is also referred to as balancing generator credits. Other uplift credits paid in the balancing market, such as lost opportunity cost credits, local constraint control credits, and dispatch differential lost opportunity credits are not included. BOR credits are calculated by segment as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time offer (startup, no load, and incremental energy offer). Segments for Balancing Operating Reserve credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Combustion turbines (CTs) received $136.4 million or 75.2 percent of all balancing operating reserve (BOR) credits in 2022. The majority of these credits, 97.8 percent, were paid to CTs committed in real time either with or without a day-ahead schedule.[21]

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal.[22] Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate

21 Operating without of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

22 *See* "Operating Reserve Make Whole Credit Education," slide 13, PJM presentation to the Resource Adequacy Senior Task Force. (April 13, 2022) <https://pjm.com/-/media/committees-groups/committees/mic/2022/20220413/item-11a---operating-reserve-make-whole-credits-education.ashx>.

eligibility for receiving balancing operating reserve credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Balancing operating reserve credits to generators increased by 42.2 percent in 2022 compared to 2021, despite PJM's decreased commitment and dispatch of CTs. Balancing operating reserve credits paid to units in the DOM Zone increased by 31.7 percent. Elliott resulted in a large increase in BOR uplift. The BOR uplift paid on December 24, 2022, was 15.0 percent of annual BOR uplift credits.

Table 4-8 shows monthly day-ahead and real-time generation by combustion turbines. In 2022, generation by combustion turbines was 4.0 percent higher in the real-time energy market than in the day-ahead energy market. Table 4-8 shows that only 1.5 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 29.0 percent of generation from combustion turbines in the real-time market was uneconomic and was paid $136.4 million in BOR credits. The decreased level of uneconomic real-time generation resulted in reduced BOR credits during 2022.

Table 4-8 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: 2022

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Ratio of Day-Ahead to Real-Time Generation
Jan	1,754	0.9%	$0.0	1,056	23.4%	$9.2	1.7
Feb	561	3.0%	$0.0	361	19.6%	$2.2	1.6
Mar	254	2.2%	$0.0	306	52.3%	$4.9	0.8
Apr	416	2.2%	$0.0	738	39.7%	$11.0	0.6
May	776	1.0%	$0.1	1,031	30.3%	$8.8	0.8
Jun	1,563	1.6%	$0.2	1,685	22.2%	$11.1	0.9
Jul	2,187	1.0%	$0.0	2,467	24.6%	$18.0	0.9
Aug	1,776	0.8%	$0.1	2,381	26.5%	$23.2	0.7
Sep	1,126	0.4%	$0.0	1,288	29.2%	$9.3	0.9
Total	14,009	1.5%	$0.9	14,599	29.0%	$136.4	1.0

In 2022, balancing operating reserve credits paid to combustion turbines were $136.4 million. Of that amount, $133.4 million, or 73.5 percent of the $181.6 million in total balancing generator credits, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-9).

Table 4-9 shows real-time generation by combustion turbines by day-ahead commitment status in 2022 and 2021. In 2022, 65.4 percent of real-time CT generation was from CTs that operated on a day-ahead schedule.

In 2022, real-time CT generation operating consistent with their day-ahead schedule decreased compared to 2021. CTs that operate on a day-ahead schedule tend to receive lower BOR credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. Day-ahead LMPs support committing the units because the day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, amounting to greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Table 4-9 Real-time generation by combustion turbines by day-ahead commitment: 2021 through 2022

		Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month-Year		Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
2021	Jan	389	54.0%	44.4%	$0.1	331	46.0%	71.2%	$4.4
	Feb	457	60.3%	43.8%	$0.2	301	39.7%	72.8%	$9.7
	Mar	755	74.5%	35.6%	$0.1	258	25.5%	63.8%	$4.4
	Apr	1,458	65.7%	28.4%	$0.1	760	34.3%	74.4%	$16.0
	May	886	70.8%	32.6%	$0.0	365	29.2%	58.9%	$5.0
	Jun	1,718	65.8%	28.7%	$0.2	891	34.2%	50.5%	$12.1
	Jul	2,391	69.1%	24.5%	$0.3	1,070	30.9%	51.8%	$16.5
	Aug	2,880	69.2%	22.9%	$0.3	1,284	30.8%	50.4%	$17.9
	Sep	1,032	74.5%	20.5%	$0.1	353	25.5%	27.6%	$3.4
	Oct	1,283	65.3%	24.2%	$0.2	683	34.7%	37.9%	$10.8
	Nov	1,259	62.4%	26.3%	$0.1	759	37.6%	46.2%	$12.9
	Dec	1,099	84.2%	32.6%	$0.0	207	15.8%	46.4%	$3.9
	Total 2021	15,608	68.2%	27.5%	$1.7	7,262	31.8%	53.1%	$116.9
2022	Jan	840	79.5%	15.4%	$0.1	217	20.5%	54.6%	$9.1
	Feb	297	82.3%	12.7%	$0.1	64	17.7%	51.8%	$2.2
	Mar	126	41.1%	33.8%	$0.1	180	58.9%	65.2%	$4.9
	Apr	281	38.1%	25.7%	$0.1	457	61.9%	48.3%	$10.9
	May	551	53.4%	26.0%	$0.0	480	46.6%	35.2%	$8.8
	Jun	1,139	67.6%	18.8%	$0.4	545	32.4%	29.5%	$10.7
	Jul	1,694	68.7%	20.7%	$0.1	772	31.3%	33.2%	$17.9
	Aug	1,506	63.2%	20.2%	$0.1	876	36.8%	37.3%	$23.2
	Sep	880	68.3%	25.0%	$0.0	408	31.7%	38.3%	$9.3
	Oct	589	68.9%	35.0%	$0.2	266	31.1%	55.2%	$7.5
	Nov	809	73.5%	30.5%	$0.0	293	26.5%	59.5%	$9.8
	Dec	839	63.1%	22.1%	$1.8	490	36.9%	39.7%	$19.0
	Total	9,551	65.4%	22.5%	$3.0	5,048	34.6%	41.1%	$133.4

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[23] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-10 shows monthly day-ahead and real-time LOC credits in 2021 and 2022. In 2022, LOC credits increased by $9.6 million or 32.0 percent compared to 2021, comprised of a $5.0 million increase in day-ahead LOC and a $4.6 million increase in real-time LOC.

In 2022, wind units received $2.5 million of real-time LOC, up by $2.1 million compared to 2021. Wind units are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

23 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

LOC payments from December 23 through December 26 accounted for 24.1 percent of annual LOC payments. High prices and units committed in the day-ahead but not called on in real time combined to produce high LOC payments.

Table 4-10 Monthly lost opportunity cost credits (Millions): 2021 through 2022

	2021			2022		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.4	$0.0	$0.4	$3.3	$0.4	$3.7
Feb	$0.5	$0.0	$0.6	$1.4	$0.4	$1.8
Mar	$3.5	$0.0	$3.5	$0.5	$0.0	$0.5
Apr	$0.6	$0.0	$0.6	$0.7	$0.6	$1.3
May	$2.8	$0.1	$2.9	$0.9	$0.1	$1.0
Jun	$3.0	$0.1	$3.1	$5.1	$0.5	$5.6
Jul	$1.8	$0.1	$1.8	$4.6	$0.1	$4.7
Aug	$1.5	$0.1	$1.6	$2.5	$2.5	$5.0
Sep	$2.5	$0.5	$3.0	$1.5	$0.1	$1.7
Oct	$2.2	$0.2	$2.3	$2.6	$0.1	$2.7
Nov	$6.7	$0.5	$7.2	$1.1	$0.0	$1.1
Dec	$3.2	$0.0	$3.2	$9.3	$1.4	$10.7
Total	$28.6	$1.6	$30.2	$33.6	$6.2	$39.8
Share	94.7%	5.3%	100.0%	84.4%	15.6%	100.0%

Table 4-11 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In 2022, 9.5 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 1.3 percentage points lower than in 2021. In 2022, day-ahead generation by combustion turbines increased by 5.3 percent, day-ahead generation not requested in real time decreased by 7.3 percent, and day-ahead generation not requested in real time receiving lost opportunity costs decreased by 6.7 percent, compared to 2021. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-11 Day-ahead generation from combustion turbines and diesels (GWh): 2021 through 2022

	2021			2022		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	486	69	17	2,262	306	101
Feb	507	53	12	753	110	38
Mar	527	64	16	448	60	13
Apr	957	62	15	675	54	18
May	1,153	213	55	1,069	101	20
Jun	1,869	223	76	1,882	137	44
Jul	2,179	149	46	2,603	154	57
Aug	2,804	162	32	2,173	88	43
Sep	1,358	130	46	1,388	97	32
Oct	1,811	140	46	1,175	180	60
Nov	2,109	373	142	1,279	105	32
Dec	888	159	61	1,826	274	68
Total	16,649	1,795	565	17,533	1,664	527
Share	100.0%	10.8%	3.4%	100.0%	9.5%	3.0%

Energy Uplift Charges

Energy Uplift Charges

Total energy uplift charges increased by $111.5 million, or 62.5 percent, in 2022 compared to 2021, from $178.4 million to $289.9 million. (Table 4-12)

Table 4-12 Total energy uplift charges: 2001 through 2022

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$198.2	$70.9	55.7%	0.4%
2019	$88.5	($109.7)	(55.3%)	0.2%
2020	$90.9	$2.4	2.7%	0.3%
2021	$178.4	$87.5	96.3%	0.4%
2022	$289.9	$111.5	62.5%	0.8%

Table 4-13 shows total energy uplift charges by category in 2021 and 2022.[24] The increase of $111.5 million is comprised of a $45.1 million increase in day-ahead operating reserve charges, a $65.6 million increase in balancing operating reserve charges, a $0.6 million increase in reactive service charges, and $0.2 million increase in black start services charges.

Table 4-13 Total energy uplift charges by category: 2022[25]

Category	2021 Charges (Millions)	2022 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$13.7	$58.8	$45.1	330.4%
Balancing Operating Reserves	$163.5	$229.1	$65.6	40.1%
Reactive Services	$0.9	$1.5	$0.6	66.2%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.3	$0.5	$0.2	50.3%
Total	$178.4	$289.9	$111.5	62.5%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	0.0%	2.0%

24 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 9, 2023.

25 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 4-14 compares monthly energy uplift charges by category for 2021 and 2022.

Table 4-14 Monthly energy uplift charges: 2021 through 2022

	2021 Charges (Millions)						2022 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2	$0.7	$14.6	$0.0	$0.0	$0.0	$15.3
Feb	$0.9	$13.7	$0.1	$0.0	$0.0	$14.6	$0.5	$5.1	$0.0	$0.0	$0.1	$5.6
Mar	$2.8	$8.5	$0.0	$0.0	$0.1	$11.4	$0.5	$7.0	$0.2	$0.0	$0.0	$7.8
Apr	$0.8	$17.1	$0.0	$0.0	$0.0	$18.0	$0.6	$13.4	$0.0	$0.0	$0.1	$14.1
May	$0.6	$8.7	$0.0	$0.0	$0.0	$9.4	$2.3	$12.1	$0.8	$0.0	$0.1	$15.3
Jun	$1.3	$16.5	$0.0	$0.0	$0.0	$17.8	$4.1	$20.1	$0.0	$0.0	$0.0	$24.2
Jul	$0.6	$19.7	$0.0	$0.0	$0.0	$20.3	$11.0	$25.7	$0.0	$0.0	$0.0	$36.7
Aug	$1.1	$21.2	$0.0	$0.0	$0.0	$22.3	$8.3	$32.1	$0.2	$0.0	$0.0	$40.6
Sep	$1.9	$7.3	$0.0	$0.0	$0.0	$9.2	$7.2	$13.4	$0.0	$0.0	$0.0	$20.6
Oct	$0.4	$14.2	$0.0	$0.0	$0.1	$14.7	$0.3	$12.8	$0.1	$0.0	$0.1	$13.3
Nov	$0.8	$21.6	$0.2	$0.0	$0.0	$22.6	$1.2	$13.2	$0.0	$0.0	$0.1	$14.5
Dec	$1.6	$8.2	$0.0	$0.0	$0.0	$9.9	$22.0	$59.5	$0.2	$0.0	$0.0	$81.7
Total	$13.7	$163.5	$0.9	$0.0	$0.3	$178.4	$58.8	$229.1	$1.5	$0.0	$0.5	$289.9
Share	7.7%	91.7%	0.5%	0.0%	0.2%	100.0%	20.3%	79.0%	0.5%	0.0%	0.2%	100.0%

Table 4-15 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[26] [27] Day-ahead operating reserve charges increased by $45.1 million or 330.4 percent in 2022 compared to 2021.

Table 4-15 Day-ahead operating reserve charges: 2021 and 2022

Type	2021 Charges (Millions)	2022 Charges (Millions)	Change (Millions)	2021 Share	2022 Share
Day-Ahead Operating Reserve Charges	$13.7	$58.8	$45.1	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$13.7	$58.8	$45.1	100.0%	100.0%

Table 4-16 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $65.6 million or 40.1 percent in 2022 compared to 2021.

Table 4-16 Balancing operating reserve charges: 2021 and 2022

Type	2021 Charges (Millions)	2022 Charges (Millions)	Change (Millions)	2021 Share	2022 Share
Balancing Operating Reserve Reliability Charges	$63.1	$84.5	$21.4	38.6%	36.9%
Balancing Operating Reserve Deviation Charges	$95.6	$141.4	$45.8	58.5%	61.7%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Balancing Local Constraint Charges	$4.8	$3.2	($1.7)	3.0%	1.4%
Total	$163.5	$229.1	$65.6	100.0%	100.0%

Table 4-17 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In 2022, energy lost opportunity cost deviation charges decreased by $9.6 million or 32.0 percent, and make whole deviation charges decreased by $36.2 million or 55.3 percent compared to 2021.

26 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.

27 See the *2022 State of the Market Report for PJM*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-17 Balancing operating reserve deviation charges: 2021 and 2022

Charge Attributable To	2021 Charges (Millions)	2022 Charges (Millions)	Change (Millions)	2021 Share	2022 Share
Make Whole Payments to Generators and Imports	$65.4	$101.6	$36.2	68.4%	71.8%
Energy Lost Opportunity Cost	$30.2	$39.8	$9.6	31.6%	28.2%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$95.6	$141.4	$45.8	100.0%	100.0%

Table 4-18 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.6 million or 66.2 percent in 2022, compared to 2021.

Table 4-18 Additional energy uplift charges: 2021 and 2022

Type	2021 Charges (Millions)	2022 Charges (Millions)	Change (Millions)	2021 Share	2022 Share
Reactive Services Charges	$0.9	$1.5	$0.6	74.2%	76.1%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.3	$0.5	$0.2	25.8%	23.9%
Total	$1.2	$2.0	$0.8	100.0%	100.0%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates ten separate rates: a day-ahead operating reserve rate, a reliability rate for each region (RTO, East, or West), a deviation rate for each region, a lost opportunity cost rate, a canceled resources rate, and a dispatch differential lost opportunity cost rate.

Table 4-19 illustrates the composition of charges and the transactions included in the charge calculation. For example, balancing operating reserve charges for deviations are calculated by adding the RTO deviation rate, the regional deviation rates, the LOC rate, and the canceled resources rate. For example, the INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.[28]

Table 4-19 Composition of charges

		Transaction / Resource Type								
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X	X
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X					
	Regional (East or West) Reliability Rate	X			X					
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X
	LOC Rate	X	X	X	X		X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	
Reactive Services	Implicit Rates	X								
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]				
Synchronous Condensing	Implicit Rate	X			X					

[1] Dynamic scheduled transactions are exempt from operating reserve charges.
[2] Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.
[3] Load is charged black start services based on their zonal peak load contribution.
[4] Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

28 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

Figure 4-1 shows the daily day-ahead operating reserve rate for 2021 and 2022. The average rate during 2022 was $0.062 per MWh, $0.046 per MWh higher than the average in 2021. The highest rate during 2022 occurred during Elliott on December 25, $4.351 per MWh, $4.141 per MWh higher than the $0.210 per MWh reached in in 2021, on August 26. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2021 or 2022.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2021 through 2022

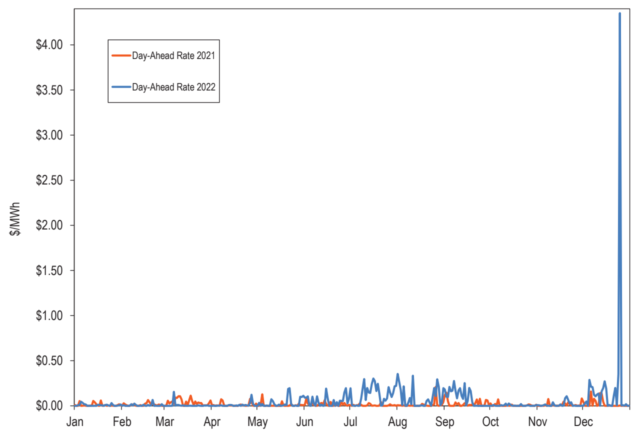

Figure 4-2 shows the RTO and the regional reliability rates for 2021 and 2022. The average RTO reliability rate in 2022 decreased to $ 0.090 per MWh from $0.072 in 2021. The highest RTO reliability rate in 2022 occurred during Elliott on December 24 when the rate reached $3.813 per MWh, $3.150 per MWh higher than the $0.662 per MWh rate reached in 2021, on June 29.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2021 through 2022

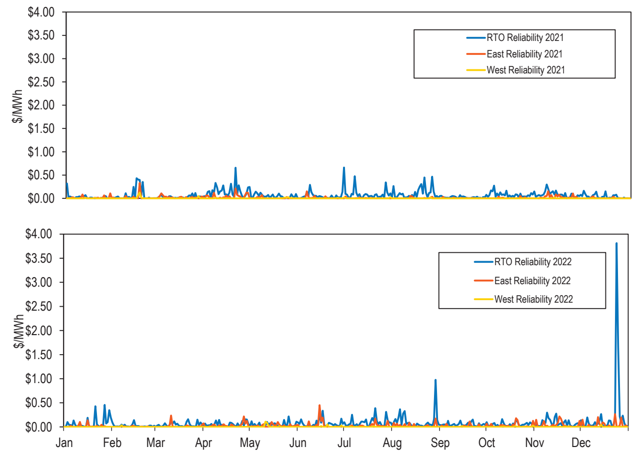

Figure 4-3 shows the RTO and regional deviation rates for 2021 and 2022. The average RTO deviation rate in 2022 was $0.269 per MWh. The highest daily rate during 2022 occurred during Elliott on December 24, when the RTO deviation rate reached $10.991 per MWh, $8.537 per MWh higher than the $2.454 per MWh rate reached in 2021, on August 17.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2021 through 2022

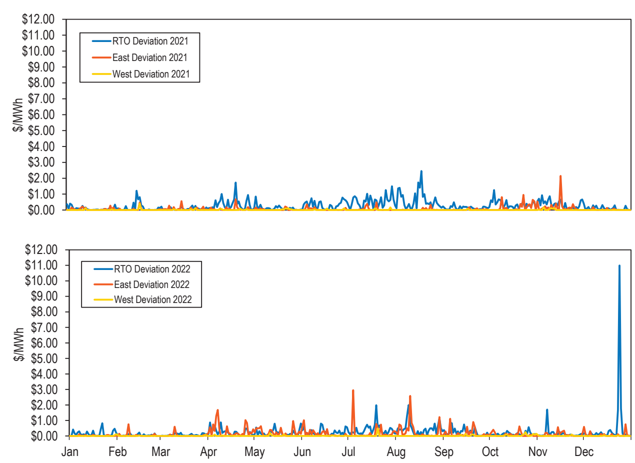

Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2021 and 2022. The average lost opportunity cost rate in 2022 was $0.139 per MWh. The highest lost opportunity cost rate in 2022 occurred on June 13, when it reached $3.808 per MWh, $1.877 per MWh more than the $1.931 per MWh rate reached in 2021, on December 7.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2021 through 2022

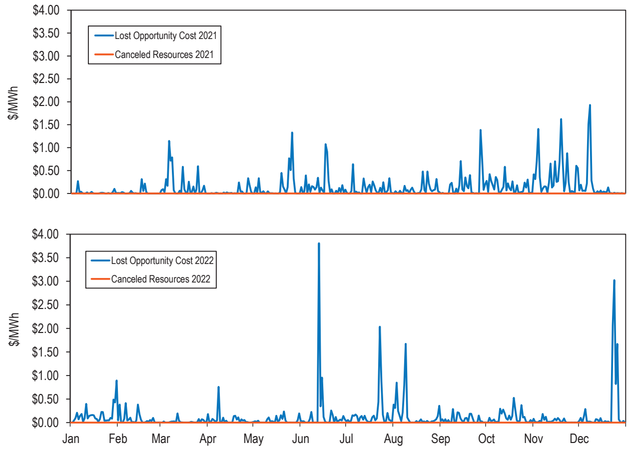

Table 4-20 shows the average rates for each region in each category for 2021 and 2022.

Table 4-20 Operating reserve rates ($/MWh): 2021 and 2022

Rate	2021 ($/MWh)	2022 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.016	0.062	0.046	296.5%
Day-Ahead with Unallocated Congestion	0.016	0.062	0.046	296.5%
RTO Reliability	0.072	0.090	0.019	26.3%
East Reliability	0.013	0.025	0.012	94.5%
West Reliability	0.002	0.002	0.000	1.7%
RTO Deviation	0.270	0.269	(0.000)	(0.2%)
East Deviation	0.061	0.133	0.072	119.1%
West Deviation	0.009	0.009	0.000	1.1%
Lost Opportunity Cost	0.139	0.131	(0.008)	(5.9%)
Canceled Resources	0.000	0.000	NA	N/A
Dispatch Differential Lost Opportunity Cost	NA	0.005	NA	N/A

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[29] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-21 shows the reactive services rates associated with local voltage support in 2021 and 2022. Table 4-21 shows that in 2022 only six zones incurred reactive services charges.

Table 4-21 Local voltage support rates: 2021 and 2022

Control Zone	2021 ($/MWh)	2022 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(100.0%)
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.009	0.009	NA
COMED	0.002	0.000	(0.002)	(100.0%)
DAY	0.000	0.000	0.000	0.0%
DUKE	0.000	0.000	0.000	0.0%
DUQ	0.000	0.000	0.000	0.0%
DOM	0.000	0.002	0.002	NA
DPL	0.000	0.013	0.013	30,553.2%
EKPC	0.000	0.000	(0.000)	(100.0%)
JCPLC	0.000	0.000	0.000	0.0%
MEC	0.000	0.004	0.003	705.1%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PE	0.000	0.000	0.000	0.0%
PEPCO	0.000	0.017	0.017	NA
PPL	0.017	0.005	(0.012)	(70.9%)
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Geography of Charges and Credits

Table 4-22 shows the geography of charges and credits in 2022. Table 4-22 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, load, virtual transactions, and generators in the PPL Control Zone paid 4.9 percent of all operating reserve charges allocated regionally while resources in

29 See *2021 State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.

the PPL Control Zone were paid 6.3 percent of the corresponding credits. The PPL Control Zone received fewer operating reserve credits than operating reserve charges paid and had 5.2 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.4 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 12.3 percent of the corresponding credits. The BGE Control Zone received fewer operating reserve credits than operating reserve charges paid and had 32.7 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-22 also shows that 87.2 percent of all charges were allocated in control zones, 5.3 percent in hubs and aggregates and 7.5 percent in interfaces.

Table 4-22 Geography of regional charges and credits: 2022

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$3.6	$2.6	($1.0)	1.3%	0.9%	1.5%	0.0%
	AEP	$38.9	$37.2	($1.6)	13.7%	13.1%	2.4%	0.0%
	APS	$12.0	$5.5	($6.5)	4.2%	1.9%	9.6%	0.0%
	ATSI	$17.2	$10.1	($7.1)	6.0%	3.5%	10.6%	0.0%
	BGE	$9.7	$34.9	$25.2	3.4%	12.3%	0.0%	32.7%
	COMED	$27.3	$27.3	$0.0	9.6%	9.6%	0.0%	0.0%
	DAY	$4.9	$7.9	$2.9	1.7%	2.8%	0.0%	3.8%
	DUKE	$8.7	$4.8	($3.9)	3.1%	1.7%	5.8%	0.0%
	DUQ	$3.6	$0.6	($3.0)	1.3%	0.2%	4.5%	0.0%
	DOM	$39.5	$51.6	$12.1	13.9%	18.1%	0.0%	15.7%
	DPL	$6.9	$10.9	$4.1	2.4%	3.8%	0.0%	5.3%
	EKPC	$7.7	$9.9	$2.3	2.7%	3.5%	0.0%	2.9%
	External	$0.0	$5.4	$5.4	0.0%	1.9%	0.0%	7.0%
	JCPLC	$6.6	$5.4	($1.2)	2.3%	1.9%	1.8%	0.0%
	MEC	$5.5	$7.1	$1.6	1.9%	2.5%	0.0%	2.0%
	OVEC	$1.0	$0.1	($1.0)	0.4%	0.0%	1.4%	0.0%
	PECO	$11.7	$3.8	($7.9)	4.1%	1.3%	11.7%	0.0%
	PE	$6.9	$5.3	($1.5)	2.4%	1.9%	2.3%	0.0%
	PEPCO	$8.8	$28.3	$19.5	3.1%	9.9%	0.0%	25.3%
	PPL	$13.9	$17.9	$4.0	4.9%	6.3%	0.0%	5.2%
	PSEG	$12.8	$8.1	($4.7)	4.5%	2.9%	6.9%	0.0%
	REC	$1.2	$0.0	($1.2)	0.4%	0.0%	1.7%	0.0%
	All Zones	$248.3	$284.7	$36.4	87.2%	100.0%	60.4%	100.0%
Hubs and Aggregates	AEP - Dayton	$2.7	$0.0	($2.7)	1.0%	0.0%	4.0%	0.0%
	Dominion	$2.4	$0.0	($2.4)	0.9%	0.0%	3.6%	0.0%
	Eastern	$1.3	$0.0	($1.3)	0.5%	0.0%	2.0%	0.0%
	New Jersey	$1.2	$0.0	($1.2)	0.4%	0.0%	1.7%	0.0%
	Ohio	$2.3	$0.0	($2.3)	0.8%	0.0%	3.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$5.0	$0.0	($5.0)	1.8%	0.0%	7.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$15.0	$0.0	($15.0)	5.3%	0.0%	22.2%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$1.3	$0.0	($1.3)	0.4%	0.0%	1.9%	0.0%
	IMO	$1.3	$0.0	($1.3)	0.5%	0.0%	1.9%	0.0%
	Linden	$0.7	$0.0	($0.7)	0.2%	0.0%	1.0%	0.0%
	MISO	$4.8	$0.0	($4.8)	1.7%	0.0%	7.2%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$1.0	$0.0	($1.0)	0.4%	0.0%	1.5%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$2.6	$0.0	($2.6)	0.9%	0.0%	3.9%	0.0%
	South Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South	$9.7	$0.0	($9.7)	3.4%	0.0%	14.4%	0.0%
	All Interfaces	$21.4	$0.0	($21.4)	7.5%	0.0%	17.4%	0.0%
	Total	$284.7	$284.7	($0.0)	100.0%	100.0%	100.0%	100.0%

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-23 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[30] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[31]

Table 4-23 Dispatch status, commitment status and uplift eligibility[32]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

Energy Uplift Issues

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases. Since 2018, the cumulative resettlement requests total $15.1 million, of which PJM has agreed and resettled 9.8 percent, and 29.8 percent remain pending. The remaining 48.3 percent occurred prior to January 2021 and would now require a directive from FERC for them to be resettled.[33] PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

30 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
31 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
32 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

33 OATT § 10.4.

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[34] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-24 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2022, balancing operating reserve credits would have been $41.8 million or 27.6 percent lower if they were calculated on a daily basis. In 2021, balancing operating reserve credits would have been $27.1 million or 21.2 percent lower if they were calculated on a daily basis.

Table 4-24 Intraday segments and daily balancing operating reserve credits: 2021 through 2022

	2021 BOR Credits (Millions)			2022 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$4.8	$4.2	($0.6)	$10.2	$8.5	($1.8)
Feb	$10.5	$9.4	($1.2)	$3.2	$2.5	($0.7)
Mar	$5.0	$4.0	($1.0)	$5.3	$4.5	($0.8)
Apr	$16.5	$15.1	($1.4)	$11.9	$9.9	($1.9)
May	$5.8	$4.7	($1.1)	$10.6	$7.9	($2.7)
Jun	$13.0	$9.8	($3.2)	$13.8	$9.7	($4.1)
Jul	$17.8	$14.0	($3.8)	$20.3	$14.5	($5.8)
Aug	$19.6	$14.5	($5.1)	$26.6	$18.7	($8.0)
Sep	$4.2	$2.4	($1.8)	$11.5	$6.1	($5.4)
Oct	$11.6	$8.7	($2.9)	$8.7	$6.6	($2.2)
Nov	$14.0	$9.9	($4.1)	$11.9	$9.8	($2.1)
Dec	$4.9	$4.0	($0.9)	$47.6	$41.2	($6.3)
Total	$127.7	$100.6	($27.1)	$181.6	$139.8	($41.8)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-25 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In 2022, LOC credits would have been $ 2.6 million or 7.6 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In 2022, LOC credits would have been $7.8 million or 23.2 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

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

Table 4-25 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: 2022

	2022 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$3.3	$2.7	($0.6)	$1.8	($1.5)
Feb	$1.4	$1.2	($0.2)	$1.0	($0.4)
Mar	$0.5	$0.4	($0.1)	$0.3	($0.2)
Apr	$0.7	$0.6	($0.2)	$0.4	($0.3)
May	$0.9	$0.6	($0.3)	$0.3	($0.6)
Jun	$5.1	$4.8	($0.3)	$4.5	($0.6)
Jul	$4.6	$4.3	($0.4)	$3.9	($0.7)
Aug	$2.5	$2.4	($0.1)	$2.1	($0.4)
Sep	$1.5	$1.3	($0.3)	$0.9	($0.6)
Oct	$2.6	$2.6	($0.1)	$2.1	($0.6)
Nov	$1.0	$1.7	$0.7	$1.4	$0.3
Dec	$9.3	$8.4	($0.9)	$7.1	($2.2)
Total	$33.6	$31.0	($2.6)	$25.8	($7.8)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[35]

Table 4-26 shows the concentration of energy uplift credits. The top 10 units received 27.0 percent of total energy uplift credits in 2022, compared to 12.5 percent in the same time period in 2021. The top 10 companies received 70.7 percent of total energy uplift credits in 2022, compared to 67.8 percent in the same time period in 2021.

Table 4-26 Top 10 units and organizations energy uplift credits: 2022[36]

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$53.5	91.0%	$57.9	98.6%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$33.8	18.6%	$123.1	67.8%
	Local Constraints Control	$2.6	82.1%	$3.2	100.0%
	Lost Opportunity Cost	$7.2	18.0%	$29.4	73.8%
	Dispatch Differential Lost Opportunity Cost	$1.0	23.3%	$3.1	68.6%
	Total Balancing	$44.7	19.5%	$158.8	69.3%
Reactive Services		$1.5	97.0%	$1.5	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.2	33.8%	$0.4	82.9%
Total		$78.4	15.1%	$204.8	39.5%

35 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits paid on and after July 1, 2019, on September 10, 2019.

36 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures.

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-27 through Table 4-31 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Table 4-27 Top 10 recipients of total uplift: 2022

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	PEP CHALKPOINT 3 F	PEPCO	$18,291,367	6.3%
2	BC BRANDON SHORES 2 F	BGE	$17,190,107	5.9%
3	BC BRANDON SHORES 1 F	BGE	$11,906,677	4.1%
4	PL BRUNNER ISLAND 3 F	PPL	$9,866,542	3.4%
5	VP MARSHRUN 3 CT	DOM	$4,005,248	1.4%
6	VP MARSHRUN 2 CT	DOM	$3,931,453	1.4%
7	VP MARSHRUN 1 CT	DOM	$3,628,973	1.3%
8	VP LOUISA 5 CT	DOM	$3,462,565	1.2%
9	PS LINDEN 2CC	PSEG	$3,091,445	1.1%
10	VP FOUR RIVERS 1 CT	DOM	$2,999,031	1.0%
Total of Top 10			$78,373,408	27.0%
Total Uplift Credits			$289,862,697	100.0%

Table 4-28 Top 10 recipients of day-ahead generation credits: 2022

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$15,481,853	26.3%
2	PEP CHALKPOINT 3 F	PEPCO	$12,832,527	21.8%
3	BC BRANDON SHORES 1 F	BGE	$10,229,685	17.4%
4	PL BRUNNER ISLAND 3 F	PPL	$5,146,198	8.8%
5	PEP ST CHARLES-KELSON RIDGE 2 CC	PEPCO	$2,381,073	4.0%
6	PEP ST CHARLES-KELSON RIDGE 1 CC	PEPCO	$2,338,994	4.0%
7	BC WAGNER 4 F	BGE	$1,581,996	2.7%
8	PEP CHALKPOINT 4 F	PEPCO	$1,544,627	2.6%
9	AEP CLINCH RIVER 2 F	AEP	$1,052,831	1.8%
10	PL BRUNNER ISLAND 2 F	PPL	$913,238	1.6%
Total of Top 10			$53,503,023	91.0%
Total day-ahead operating reserve credits			$58,799,122	100.0%

Table 4-29 Top 10 recipients of balancing operating reserve credits: 2022

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	PEP CHALKPOINT 3 F	PEPCO	$5,457,554	3.0%
2	PL BRUNNER ISLAND 3 F	PPL	$4,714,480	2.6%
3	VP MARSHRUN 3 CT	DOM	$3,849,190	2.1%
4	VP MARSHRUN 2 CT	DOM	$3,629,842	2.0%
5	VP MARSHRUN 1 CT	DOM	$3,499,335	1.9%
6	VP LOUISA 5 CT	DOM	$3,102,881	1.7%
7	PS LINDEN 2CC	PSEG	$3,019,055	1.7%
8	VP FOUR RIVERS 1 CT	DOM	$2,307,939	1.3%
9	VP DOSWELL 2 CT	DOM	$2,232,662	1.2%
10	COM 960 ELGIN 2 CT	COMED	$2,016,915	1.1%
Total of Top 10			$33,829,853	18.6%
Total balancing operating reserve credits			$181,613,859	100.0%

Table 4-30 Top 10 recipients of lost opportunity cost credits: 2022

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	EKPC BLUEGRASS 2 CT	External	$1,310,581	3.3%
2	AEP RIVERSIDE ZELDA 1 CT	AEP	$849,681	2.1%
3	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$772,844	1.9%
4	VP FOUR RIVERS 1 CT	DOM	$670,337	1.7%
5	DAY DARBY 3 CT	AEP	$614,969	1.5%
6	DAY DARBY 1 CT	AEP	$611,562	1.5%
7	DAY DARBY 2 CT	AEP	$610,397	1.5%
8	VP REMINGTON 1 CT	DOM	$591,516	1.5%
9	DPL DEMEC - CLAYTON 2 CT	DPL	$576,208	1.4%
10	DAY DARBY 5 CT	AEP	$563,188	1.4%
Total of Top 10			$7,171,283	18.0%
Total lost opportunity cost credits			$39,812,516	100.0%

Table 4-31 Top 10 recipients of dispatch differential lost opportunity cost credits: 2022[37]

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credit	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP SMITH MOUNT 1-5 H	AEP	$218,060	4.9%
2	PL HOLTWOOD 19	PPL	$215,334	4.8%
3	ME BIRDSBORO 1 CC	MEC	$102,800	2.3%
4	VP PANDA STONEWALL 1 CC	DOM	$102,095	2.3%
5	PL HUMMEL STATION 1 CC	PPL	$81,406	1.8%
6	PL SAFEHARBOR 4 H	PPL	$79,811	1.8%
7	AP LKLYN 1-4 H	AP	$75,165	1.7%
8	PL SAFEHARBOR 12 H	PPL	$63,970	1.4%
9	PL HOLTWOOD 2	PPL	$51,486	1.2%
10	PL SAFEHARBOR 8 H	PPL	$50,462	1.1%
Total of Top 10			$1,040,587	23.3%
Total dispatch differential lost opportunity cost credits			$4,471,410	11.2%

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[38] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-32 shows the uplift credits paid to committed and dispatched units in 2022 by offer type. Units received $94.1 million or 51.8 percent of balancing operating reserve credits and $27.9 million or 47.5 percent of day-ahead operating reserve credits in 2022 using price-based offers. Units received $59.5 million or 32.8 percent of balancing operating reserves and $29.7 million or 50.5 percent of day-ahead operating reserves in 2022 using cost-based offers.

37 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures.

38 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 4-32 Operating reserve credits by offer type: 2022

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total
Cost	$29.7	$59.5	$0.6	$0.3	$90.1
Price	$27.9	$94.1	$0.3	$0.1	$122.3
Price PLS	$1.2	$22.8	$0.0	$0.0	$24.0
Cost & Price	$0.0	$4.0	$0.0	$0.0	$4.0
Cost & PLS	$0.0	$0.7	$0.0	$0.0	$0.7
Price & PLS	$0.0	$0.6	$0.0	$0.0	$0.6
Total	$58.8	$181.7	$0.9	$0.4	$241.8
Share	24.3%	75.2%	0.4%	0.2%	100.0%

Table 4-33 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 56.3 percent went to units that were committed on cost schedules, which are parameter limited, 3.7 percent went to units that were committed on price PLS schedules and 0.8 percent went to units committed on price schedules as flexible as PLS. The 39.2 percent that went to units committed on a price schedule less flexible than PLS indicates an issue with the process that PJM uses to apply parameter mitigation on weather alert days. Resources should not receive uplift based on inflexible parameters during emergencies and alerts.

Table 4-33 Day-ahead operating reserve credits during weather alerts by commitment schedule: 2022

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during Hot and Cold Weather Alerts
Committed on cost (cost capped)	$12,027,274	55.0%
Committed on price schedule as flexible as PLS	$168,202	0.8%
Committed on price schedule less flexible than PLS	$8,471,705	38.8%
Committed on price PLS	$1,186,761	5.4%
Total	$21,853,942	100.0%

Fast Start Pricing

Fast start pricing was implemented on September 1, 2021. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the combined dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run.

As a result, the implementation of fast start pricing required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost for 2022 was $4.5 million. Table 4-5 shows that 29.1 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 36.2 percent to combustion turbines.

In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules. The MMU recommends that PJM not make such payments and require refunds where it has not already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

A primary argument made by the proponents of fast start pricing is that it will reduce uplift to fast start units by raising LMP, and thus revenue, when they are operating. This reduction in uplift would be most likely to occur in balancing operating reserves payments. To the extent that fast start pricing increases day-ahead prices, it may also reduce Day-Ahead Operating Reserve payments. But fast start pricing also increases other uplift payments, especially the new dispatch differential lost opportunity cost payment. Day-ahead lost opportunity cost payments to fast start resources may also increase because real-time LMPs are higher than they would be without fast start pricing.

Table 4-34 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $37.9 million in balancing operating reserve credits, or 20.9 percent of total balancing operating reserves. Fast start units received $8.4 million in day-ahead lost opportunity costs, or 25.2 percent of all lost opportunity costs. Fast start units received $0.1 million in day-ahead operating credits, or 0.1 percent of total day-ahead operating reserve credits.

Table 4-34 Monthly day-ahead operating reserves, balancing operating reserves, and day-ahead lost opportunity cost credits for fast start units: 2022

Month	Day-Ahead Operating Reserves (Millions)	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves (Millions)	Share of Monthly Balancing Operating Reserves	Day Ahead Lost Opportunity Cost Credits (Millions)	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.7	16.6%	$1.2	34.9%
Feb	$0.0	0.0%	$0.6	19.5%	$0.6	43.5%
Mar	$0.0	0.1%	$1.7	32.5%	$0.1	13.1%
Apr	$0.0	0.2%	$2.9	24.7%	$0.1	16.6%
May	$0.0	0.0%	$2.5	23.7%	$0.1	14.9%
Jun	$0.0	0.8%	$2.7	19.3%	$2.1	40.9%
Jul	$0.0	0.0%	$5.8	28.7%	$1.6	34.0%
Aug	$0.0	0.0%	$6.9	26.0%	$0.5	21.1%
Sep	$0.0	0.0%	$2.7	23.6%	$0.1	7.2%
Oct	$0.0	0.5%	$3.1	35.4%	$0.5	19.5%
Nov	$0.0	0.2%	$2.3	19.0%	$0.2	22.2%
Dec	$0.0	0.1%	$4.9	10.3%	$1.3	14.2%
Total	$0.1	0.1%	$37.9	20.9%	$8.4	41.0%

Table 4-35 shows the day-ahead, balancing operating reserves, and day-ahead lost opportunity cost credits for combustion turbines by month, also included in Table 4-34.

Table 4-35 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: 2022

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Operating Reserves	Share of Monthly Day Ahead Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.5%	$1.6	15.9%	$1.0	28.6%
Feb	$0.0	0.0%	$0.6	17.5%	$0.6	42.3%
Mar	$0.0	0.3%	$1.7	31.5%	$0.1	11.8%
Apr	$0.0	0.2%	$2.8	23.9%	$0.1	14.1%
May	$0.0	1.4%	$2.4	22.8%	$0.1	13.6%
Jun	$0.0	0.0%	$2.6	18.9%	$2.1	40.4%
Jul	$0.0	0.0%	$5.8	28.4%	$1.5	32.6%
Aug	$0.0	0.0%	$6.8	25.5%	$0.5	18.7%
Sep	$0.0	0.0%	$2.6	22.7%	$0.1	6.3%
Oct	$0.0	0.7%	$3.0	33.9%	$0.5	17.8%
Nov	$0.0	1.8%	$2.2	18.1%	$0.2	19.2%
Dec	$0.0	0.0%	$4.8	10.2%	$1.1	12.1%
Total	$0.1	0.1%	$36.8	20.3%	$7.7	37.6%