

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 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 Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits decreased by \$59.2 million, or 33.1 percent, in the first nine months of 2023 compared to the same time period in 2022, from \$178.8 million to \$119.6 million.
- **Types of energy uplift credits.** In the first nine months of 2023, total energy uplift credits included \$42.8 million in day-ahead generator credits, \$58.1 million in balancing generator credits, \$16.9 million in lost opportunity cost credits, and \$0.3 million in local constraint control credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were \$0.5 million in the first nine months of 2023. Regulation revenues should be included as an offset to uplift, but are not currently included.
- **Types of units.** In the first nine months of 2023, steam coal units received 72.8 percent of day-ahead generator credits, and combustion turbines received 78.1 percent of balancing generator credits and 87.4 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 68.9 percent of dispatch differential lost opportunity credits.
- **Day-ahead unit commitment for reliability.** In the first nine months of 2023, 0.4 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 73.7 percent received energy uplift payments.
- **Concentration of energy uplift credits.** In the first nine months of 2023, the top 10 units receiving energy uplift credits received 41.4 percent of all credits and the top 10 organizations received 75.1 percent of all credits. The average HHI for day-ahead operating reserves was 8340, the HHI for balancing generator credits was 2411 and the HHI for lost opportunity cost was 5055, all of which are classified as highly concentrated.

- **Lost opportunity cost credits.** Lost opportunity cost credits decreased by \$8.7 million, or 34.0 percent, in the first nine months of 2023, compared to the same time period in 2022, from \$25.6 million to \$16.9 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 86.3 percent of the \$16.9 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 \$15.3 million, of which PJM has resettled only \$1.4 million over the last two years, or 9.0 percent.
- **Daily uplift.** In the first nine months of 2023, balancing generator charges would have been \$12.5 million or 21.5 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) decreased by \$59.2 million, or 33.1 percent, in the first nine months of 2023 compared to the same time period in 2022, from \$178.8 million to \$119.6 million.
- **Types of Energy Uplift Charges.** In the first nine months of 2023 total uplift charges included \$42.8 million in day-ahead operating reserve charges, \$76.1 million in balancing generator charges, \$0.5 million in reactive charges, and \$0.4 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 \$0.056 per MWh in the Eastern Region. Real-time load and exports paid an average of \$0.053 per MWh. Deviations paid \$0.192 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid \$0.056 per MWh in the Western Region. Real-time load and exports paid \$0.039 per MWh. Deviations paid \$0.152 per MWh in the Western Region.

Geography of Charges and Credits

- In the first nine months of 2023, 89.0 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing generator credits) were paid by MW at control zones, 3.7 percent by MW at hubs and aggregates, and 7.4 percent by MW at interchange interfaces.
- In the first nine months of 2023, generators in the Eastern Region received 48.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2023, generators in the Western Region received 50.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2023, external pseudo tied generators received 1.0 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

⁵ See 172 FERC ¶ 61,046 (2020).

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 generator 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 generator 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: Partially 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 2022.)

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).

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 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

⁷ See 173 FERC ¶ 61,244 (2020).

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.

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 generator 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

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).

⁹ See 172 FERC ¶ 61,046 (2020).

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

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.92 (July 26, 2023).

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 \$15.3 million of incorrect uplift credits of which PJM has resettled only \$1.4 million over the last two years, or 9.0 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.

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.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response. The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing.

Table 4-1 shows the totals for each credit category during the first nine months of 2022 and 2023.¹² In the first nine months of 2023, energy uplift credits decreased by \$58.8 million or 33.0 percent compared to the same time period in 2022.

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.

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 October 10, 2023.

Table 4-1 Energy uplift credits by category: January through September, 2022 and 2023¹³

Category	Type	(Jan - Sep)	(Jan - Sep)	Change	Percent Change	2022 Share	2023 Share
		2022 Credits (Millions)	2023 Credits (Millions)				
Day-Ahead	Generators	\$35.3	\$42.8	\$7.5	21.2%	19.7%	35.8%
	Imports	\$0.0	\$0.0	\$0.0	6,068.2%	0.0%	0.0%
	Load Response	\$0.0	\$0.0	(\$0.0)	(100.0%)	0.0%	0.0%
Balancing	Canceled Resources	\$0.0	\$0.05	\$0.1	NA	0.0%	0.0%
	Generators	\$112.9	\$58.1	(\$54.8)	(48.6%)	63.1%	48.5%
	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	\$1.2	\$0.6	(\$0.6)	(53.1%)	0.7%	0.5%
	Lost Opportunity Cost	\$25.6	\$16.9	(\$8.7)	(34.0%)	14.3%	14.1%
	Dispatch Differential Lost Opportunity Cost	\$2.2	\$0.5	(\$1.7)	(77.0%)	1.2%	0.4%
Reactive Services	Day-Ahead	\$0.7	\$0.5	(\$0.3)	(34.4%)	0.4%	0.4%
	Local Constraints Control	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	\$0.2	\$0.0	(\$0.2)	(100.0%)	0.1%	0.0%
	Reactive Services	\$0.3	\$0.0	(\$0.2)	(96.4%)	0.1%	0.0%
	Synchronous Condensing	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
Black Start Services	Synchronous Condensing	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
	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	\$0.4	\$0.3	(\$0.1)	(25.9%)	0.2%	0.2%
	Lost Opportunity Cost	\$0.0	\$0.0	\$0.0	NA	0.0%	0.0%
Total		\$178.8	\$119.6	(\$59.2)	(33.1%)	100.0%	100.0%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by PJM members in proportion to their day-ahead load, day-ahead exports, virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DEC), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in

¹³ Year to year change is rounded to one tenth of a million, and includes values less than \$0.05 million.

proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

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

	Credit Category	Charges Category	Charge Responsibility	Geographic Charge Aggregation
DAY-AHEAD	Day-Ahead Operating Reserve Transaction	Day-Ahead Operating Reserves for Transactions	Day-Ahead Load, Day-Ahead Exports, DECs & UTCs	RTO Region
	Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve for Generators		
	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response		
	Unallocated Negative Load Congestion Charges	Unallocated Congestion		
	Unallocated Positive Generation Congestion Credits			
BALANCING	Balancing Generator Reserves	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	RTO, Eastern, and Western Region
		Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Dispatch Differential Lost Opportunity Cost (DDLLOC)	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	RTO Region
	Canceled Resources	Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Lost Opportunity Cost (LOC)			
	Real-Time Import Transactions			
	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations (includes virtual bids, UTCs, load, and interchange)	
Local Constraints Control	NA	Transmission Owner	NA	

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

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Generator Reactive Services		
	LOC Reactive Services		
	Condensing Reactive Services	Local Constraint Reactive Services	Transmission owner
	Synchronous Condensing LOC Reactive Services		
Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		
	Black Start LOC		

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type during the first nine months of 2022 and 2023. A combination of factors led to overall decreased uplift payments.

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 and as a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines decreased by \$59.7 million or 49.3 percent in the first nine months of 2023 compared to the same time period in 2022. In the first nine months of 2023, CTs received 87.4 percent of lost opportunity cost credits, a decrease of \$5.5 million or 37.3 percent compared to the same time period in 2022.

Uplift credits paid to steam coal units increased by \$7.1 million or 23.5 percent during the first nine months of 2023 compared to the same time period in 2022. In the first nine months of 2023, day-ahead uplift credits for reliability totaled \$39.5 million, compared to \$32.1 million during the same time period in 2022. In the first nine months of 2023, day-ahead credits for reliability in the BGE and PEPCO Zones made up 91.0 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 Zone received 74.4 percent of day-ahead credits.

Uplift credits paid to non-coal (gas or oil fired) steam units decreased by \$0.6 million or 4.3 percent during the first nine months of 2023 compared to the same time period in 2022. The decrease in balancing generator credits to gas or oil fired steam units was due to a small number of units in the PEPCO and PPL Zones. In the first nine months of 2023, gas or oil fired steam units received \$14.1 million, or 11.8 percent of total credits, compared to \$14.7 million and 8.2 percent during the same time period in 2022. The slight increase in day-ahead operating reserve payments to gas or oil fired steam

units offset the slight decrease in balancing operating generator credits, and was primarily due to an increase in reliability needs during the first nine months of 2023 compared to 2022.

Uplift credits paid to combined cycle units decreased by \$6.2 million or 62.5 percent during the first nine months of 2023 compared to the same time period in 2022.

In the first nine months of 2023, uplift credits to wind units were \$0.5 million, down by 4.7 percent compared to the same time period in 2022.

Table 4-4 Total energy uplift credits by unit type: January through September, 2022 and 2023^{14 15}

Unit Type	(Jan - Sep) 2022 Credits (Millions)	(Jan - Sep) 2023 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2022 Share	(Jan - Sep) 2023 Share
Combined Cycle	\$9.9	\$3.7	(\$6.2)	(62.4%)	5.5%	3.1%
Combustion Turbine	\$121.2	\$61.4	(\$59.7)	(49.3%)	67.8%	51.3%
Diesel	\$1.9	\$2.6	\$0.7	36.2%	1.0%	2.1%
Hydro	\$0.3	\$0.0	(\$0.3)	(98.6%)	0.2%	0.0%
Nuclear	\$0.0	\$0.0	(\$0.0)	(69.9%)	0.0%	0.0%
Solar	\$0.1	\$0.1	(\$0.0)	(17.6%)	0.0%	0.1%
Steam - Coal	\$30.2	\$37.2	\$7.1	23.5%	16.9%	31.1%
Steam - Other	\$14.7	\$14.1	(\$0.6)	(4.3%)	8.2%	11.8%
Wind	\$0.6	\$0.5	(\$0.0)	(4.7%)	0.3%	0.4%
Total	\$178.8	\$119.6	(\$59.2)	(33.1%)	100.0%	100.0%

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2023. The largest share of day-ahead credits, 72.8 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 78.1 percent of balancing credits and 87.4 percent of lost opportunity cost credits. Combustion turbines

¹⁴ Table 4-2 does not include balancing imports credits and load response credits in the total amounts.

¹⁵ 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.

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.

Table 4-5 Energy uplift credits by unit type: January through September, 2023¹⁶

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	1.0%	3.9%	0.0%	0.0%	4.4%	0.0%	0.0%	18.1%	42.1%
Combustion Turbine	0.9%	78.1%	0.0%	79.0%	87.4%	23.4%	0.0%	81.8%	26.9%
Diesel	0.0%	2.8%	0.0%	2.9%	5.3%	0.0%	0.0%	0.1%	0.8%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
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%	0.4%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	72.8%	9.5%	100.0%	0.0%	0.0%	76.6%	0.0%	0.0%	26.3%
Steam - Other	25.3%	5.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Wind	0.0%	0.0%	0.0%	18.0%	2.4%	0.0%	0.0%	0.0%	1.6%
Total (Millions)	\$42.8	\$58.1	\$0.1	\$0.6	\$16.9	\$0.5	\$0.0	\$0.3	\$0.5

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.¹⁷ 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.¹⁸ 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 decreased by 0.2 percent during the first nine months of 2023 compared to 2022, from 2,258.4 GWh during the first nine months of 2022 to 2,253.3 GWh during the first nine months of 2023.

¹⁶ The data in the Uplift section of the 2022 Annual 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.

¹⁷ See OA Schedule 1 § 3.2.3(b).

¹⁸ See OA Schedule 1 § 3.2.3(a).

Table 4-6 Day-ahead generation committed for reliability (GWh): January 2022 through September 2023

	2022			2023			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	81,373	0	0.0%	71,124	30	0.0%	NA
Feb	68,253	37	0.1%	63,475	34	0.1%	(10.0%)
Mar	66,579	4	0.0%	67,239	28	0.0%	667.7%
Apr	57,663	8	0.0%	57,403	43	0.1%	437.4%
May	63,309	389	0.6%	60,290	41	0.1%	(89.5%)
Jun	70,849	417	0.6%	67,940	101	0.1%	(75.9%)
Jul	81,815	594	0.7%	82,998	751	0.9%	26.5%
Aug	80,627	432	0.5%	80,191	564	0.7%	30.7%
Sep	67,871	378	0.6%	68,163	662	1.0%	75.0%
Oct	59,982	0	0.0%				NA
Nov	62,046	49	0.1%				NA
Dec	74,777	477	0.6%				NA
Total (Jan - Sep)	638,339	2,258	0.4%	618,823	2,253	0.4%	(0.2%)
Total	835,145	2,785	0.3%	618,823	2,253	0.4%	(0.2%)

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 in the first nine months of 2023 were \$42.8 million, of which \$39.5 million or 92.4 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 \$40.9 million or 95.6 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 the first nine months of 2023, 74.2 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits (including day-ahead reactive services). The remaining 25.8 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): January through September, 2023

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	23.9	5.9	29.9
Feb	0.0	33.7	0.0	33.7
Mar	0.0	19.5	8.7	28.2
Apr	6.0	37.5	0.0	43.5
May	0.0	29.7	10.9	40.6
Jun	0.0	47.6	53.0	100.6
Jul	0.0	475.8	275.3	751.2
Aug	0.0	498.7	65.1	563.9
Sep	4.2	495.2	162.4	661.8
Total (Jan - Sep)	10.2	1,661.6	581.4	2,253.3
Share	0.5%	73.7%	25.8%	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 all of their operating costs from market revenues. The category of balancing operating reserves includes multiple credit types that are paid to units operating uneconomically in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. The largest category of balancing operating reserves are the balancing generator credits. Balancing generator 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 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 are treated as new segments. Combustion turbines (CTs) received \$45.1 million or 78.1 percent of all balancing generator credits in the first nine months of 2023. The majority of these credits, 98.4

percent, were paid to CTs committed in real time either with or without a day-ahead schedule.¹⁹

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.²⁰ 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 eligibility for receiving balancing generator 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 generator credits decreased by 48.6 percent in the first nine months of 2023 compared to the same time period in 2022, despite PJM's increased commitment and dispatch of CTs. Balancing generator credits paid to units in the DOM Zone decreased by 58.4 percent.

Table 4-8 shows monthly day-ahead and real-time generation by combustion turbines. In the first nine months of 2023, generation by combustion turbines

¹⁹ 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.

²⁰ 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>>.

was 0.6 percent higher in the real-time energy market than in the day-ahead energy market. Table 4-8 shows that only 2.6 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 27.6 percent of generation from combustion turbines in the real-time market was uneconomic and was paid \$45.1 million in balancing generator credits. The decreased level of uneconomic real-time generation resulted in reduced balancing generator credits during the first nine months of 2023.

Table 4-8 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: January through September, 2023

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	601	0.9%	\$0.0	521	27.6%	\$3.2	1.2
Feb	604	1.5%	\$0.0	364	34.9%	\$1.4	1.7
Mar	534	0.6%	\$0.0	534	36.2%	\$3.7	1.0
Apr	1,210	1.3%	\$0.0	1,377	39.4%	\$9.6	0.9
May	1,476	1.2%	\$0.0	1,656	33.3%	\$8.6	0.9
Jun	1,632	4.9%	\$0.1	1,875	21.6%	\$4.2	0.9
Jul	2,944	3.5%	\$0.2	2,883	21.2%	\$5.8	1.0
Aug	2,372	2.7%	\$0.1	2,206	21.8%	\$3.6	1.1
Sep	1,504	2.7%	\$0.0	1,543	33.9%	\$4.9	1.0
Total (Jan - Sep)	12,877	2.6%	\$0.4	12,960	27.6%	\$45.1	1.0

In the first nine months of 2023, balancing operating reserve credits paid to combustion turbines were \$45.1 million. Of that amount, \$44.3 million, or 76.4 percent of the \$58.1 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 the first nine months of 2023 and 2022. In the first nine months of 2023, 75.3 percent of real-time CT generation was from CTs that operated on a day-ahead schedule.

In the first nine months of 2023, real-time CT generation operating consistent with their day-ahead schedule increased compared to the same time period in

2022. In the first nine months of 2023, 75.3 percent of real-time generation by CTs was consistent with a day-ahead schedule, compared to 64.7 percent for the first nine months of 2022. CTs that operate on a day-ahead schedule tend to receive lower balancing generator 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: January 2022 through September 2023

Month-Year	Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
	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)
2022								
Jan	840	79.5%	15.3%	\$0.1	217	20.5%	54.3%	\$9.0
Feb	297	82.3%	12.6%	\$0.1	64	17.7%	51.4%	\$2.1
Mar	126	41.1%	33.7%	\$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%	\$0.2	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	841	63.1%	22.1%	\$2.0	491	36.9%	39.8%	\$19.8
Total 2022 (Jan - Sep)	7,313	64.7%	20.7%	\$1.0	3,999	35.3%	39.0%	\$96.8
2023								
Jan	370	70.9%	17.8%	\$0.0	151	29.1%	51.6%	\$3.2
Feb	284	78.1%	30.1%	\$0.0	80	21.9%	52.1%	\$1.4
Mar	379	71.0%	26.1%	\$0.1	155	29.0%	60.7%	\$3.6
Apr	839	61.0%	23.9%	\$0.1	538	39.0%	63.7%	\$9.5
May	1,141	68.9%	18.4%	\$0.0	516	31.1%	66.4%	\$8.6
Jun	1,349	71.9%	12.8%	\$0.0	526	28.1%	44.0%	\$4.2
Jul	2,328	80.8%	17.9%	\$0.1	555	19.2%	35.3%	\$5.7
Aug	1,851	83.9%	18.5%	\$0.2	355	16.1%	38.5%	\$3.4
Sep	1,211	78.5%	26.8%	\$0.2	332	21.5%	59.7%	\$4.7
Total 2023 (Jan - Sep)	9,753	75.3%	19.7%	\$0.7	3,207	24.7%	51.8%	\$44.3

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.²¹ 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.

²¹ Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

Table 4-10 shows monthly day-ahead and real-time LOC credits during the first nine months of 2022 and 2023. In the first nine months of 2023, LOC credits decreased by \$8.4 million or 33.1 percent compared to the same time period in 2022, comprised of a \$5.1 million decrease in day-ahead LOC and a \$3.9 million decrease in real-time LOC.

In the first nine months of 2023, wind units received \$0.5 million of real-time LOC, up by less than \$0.1 million compared to the same time period in 2022. 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).

Table 4-10 Monthly lost opportunity cost credits (Millions): January 2022 through September 2023

	2022			2023		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	\$3.3	\$0.4	\$3.7	\$1.9	\$0.0	\$1.9
Feb	\$1.4	\$0.4	\$1.8	\$0.6	\$0.3	\$0.9
Mar	\$0.5	\$0.0	\$0.5	\$0.7	\$0.0	\$0.7
Apr	\$0.7	\$0.6	\$1.3	\$1.3	\$0.1	\$1.5
May	\$0.9	\$0.1	\$1.0	\$1.5	\$0.0	\$1.5
Jun	\$5.1	\$0.5	\$5.6	\$1.1	\$0.3	\$1.4
Jul	\$4.6	\$0.1	\$4.7	\$4.2	\$0.0	\$4.2
Aug	\$2.5	\$2.5	\$5.0	\$2.2	\$0.0	\$2.2
Sep	\$1.5	\$0.1	\$1.7	\$2.0	\$0.0	\$2.0
Oct	\$2.6	\$0.1	\$2.7			
Nov	\$1.0	\$0.0	\$1.0			
Dec	\$7.6	\$1.8	\$9.3			
Total (Jan - Sep)	\$20.6	\$4.7	\$25.3	\$15.5	\$0.8	\$16.3
Share (Jan - Sep)	81.4%	18.6%	100.0%	95.2%	4.8%	100.0%
Total	\$31.8	\$6.5	\$38.4	\$15.5	\$0.8	\$16.3
Share	82.9%	17.1%	100.0%	95.2%	4.8%	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 the first nine months of 2023, 9.3 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 1.0 percentage points higher than during the first nine months of 2022. In the first nine months of 2023, day-ahead generation by combustion turbines increased by 15.8 percent, day-ahead generation not requested in real time increased by 29.5 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 35.1 percent, compared to the same time period in 2022. 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): January 2022 through September 2023

	2022			2023		
	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	2,262	306	101	830	158	58
Feb	753	110	38	809	148	30
Mar	448	60	13	740	73	21
Apr	675	54	18	1,448	162	68
May	1,069	101	20	1,823	162	73
Jun	1,882	137	44	2,009	146	56
Jul	2,603	154	57	3,407	293	85
Aug	2,173	88	43	2,580	199	76
Sep	1,388	96	32	1,701	91	27
Oct	1,175	178	60			
Nov	1,279	104	31			
Dec	1,826	262	63			
Total (Jan - Sep)	13,253	1,106	366	15,346	1,432	495
Share (Jan - Sep)	100.0%	8.3%	2.8%	100.0%	9.3%	3.2%

Energy Uplift Charges

Energy Uplift Charges

Total energy uplift charges decreased by \$59.2 million, or 33.1 percent, in the first nine months of 2023 compared to the same time period in 2022, from \$178.8 million to \$119.6 million.

Table 4-12 shows total energy uplift charges by category during the first nine months of 2022 and 2023.²² The decrease of \$59.2 million is comprised of a \$7.5 million increase in day-ahead operating reserve charges, a \$65.8 million decrease in balancing generator charges, a \$0.7 million decrease in reactive service charges, and \$0.1 million decrease in black start services charges.

Table 4-12 Total energy uplift charges by category: January through September, 2022 and 2023²³

Category	(Jan - Sep) 2022 Charges (Millions)	(Jan - Sep) 2023 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	\$35.3	\$42.8	\$7.5	21.2%
Balancing Operating Reserves	\$141.9	\$76.1	(\$65.8)	(46.4%)
Reactive Services	\$1.2	\$0.5	(\$0.7)	(59.2%)
Synchronous Condensing	\$0.0	\$0.0	\$0.0	0.0%
Black Start Services	\$0.4	\$0.3	(\$0.1)	(25.9%)
Total	\$178.8	\$119.6	(\$59.2)	(33.1%)
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.3%	0.1%	20.2%

Table 4-13 compares monthly energy uplift charges by category for 2022 and the first nine months of 2023.

Table 4-13 Monthly energy uplift charges: January 2022 through September 2023

	2022 Charges (Millions)						2023 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	\$14.3	\$0.0	\$0.0	\$0.0	\$15.0	\$1.7	\$5.97	\$0.0	\$0.0	\$0.0	\$7.7
Feb	\$0.5	\$5.0	\$0.0	\$0.0	\$0.1	\$5.6	\$1.0	\$4.49	\$0.0	\$0.0	\$0.1	\$5.6
Mar	\$0.5	\$6.9	\$0.2	\$0.0	\$0.0	\$7.7	\$1.3	\$4.94	\$0.0	\$0.0	\$0.1	\$6.3
Apr	\$0.6	\$13.1	\$0.0	\$0.0	\$0.1	\$13.7	\$2.0	\$12.16	\$0.4	\$0.0	\$0.1	\$14.6
May	\$2.3	\$11.8	\$0.8	\$0.0	\$0.1	\$15.0	\$0.4	\$11.01	\$0.0	\$0.0	\$0.0	\$11.5
Jun	\$4.1	\$19.7	\$0.0	\$0.0	\$0.0	\$23.9	\$1.8	\$7.15	\$0.0	\$0.0	\$0.0	\$8.9
Jul	\$11.0	\$25.6	\$0.0	\$0.0	\$0.0	\$36.6	\$10.6	\$13.13	\$0.0	\$0.0	\$0.0	\$23.8
Aug	\$8.3	\$32.1	\$0.2	\$0.0	\$0.0	\$40.6	\$12.0	\$7.46	\$0.0	\$0.0	\$0.0	\$19.5
Sep	\$7.2	\$13.4	\$0.0	\$0.0	\$0.0	\$20.6	\$11.9	\$9.80	\$0.1	\$0.0	\$0.0	\$21.8
Oct	\$0.3	\$12.8	\$0.1	\$0.0	\$0.1	\$13.3						
Nov	\$1.2	\$13.2	\$0.0	\$0.0	\$0.1	\$14.5						
Dec	\$22.0	\$65.0	\$0.2	\$0.0	\$0.0	\$87.2						
Total (Jan - Sep)	\$35.3	\$141.9	\$1.2	\$0.0	\$0.4	\$178.8	\$42.8	\$76.1	\$0.5	\$0.0	\$0.3	\$119.6
Share (Jan - Sep)	19.7%	79.4%	0.7%	0.0%	0.2%	100.0%	35.8%	63.6%	0.4%	0.0%	0.2%	100.0%
Total	\$58.8	\$233.0	\$1.5	\$0.0	\$0.5	\$293.7	\$42.8	\$76.1	\$0.5	\$0.0	\$0.3	\$119.6
Share	20.0%	79.3%	0.5%	0.0%	0.2%	100.0%	35.8%	63.6%	0.4%	0.0%	0.2%	100.0%

²² 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.

²³ 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 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.^{24 25} Day-ahead operating reserve charges increased by \$7.5 million or 21.2 percent in the first nine months of 2023 compared to the same time period in 2022.

Table 4-14 Day-ahead operating reserve charges: January through September, 2022 and 2023

Type	(Jan - Sep) 2022 Charges (Millions)	(Jan - Sep) 2023 Charges (Millions)	Change (Millions)	(Jan - Sep) 2022 Share	(Jan - Sep) 2023 Share
Day-Ahead Operating Reserve Charges	\$35.3	\$42.8	\$7.5	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	\$35.3	\$42.8	\$7.5	100.0%	100.0%

Table 4-15 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 \$65.8 million or 46.4 percent in the first nine months of 2023 compared to the same time period in 2022.

Table 4-15 Balancing operating reserve charges: January through September, 2022 and 2023

Type	(Jan - Sep) 2022 Charges (Millions)	(Jan - Sep) 2023 Charges (Millions)	Change (Millions)	(Jan - Sep) 2022 Share	(Jan - Sep) 2023 Share
Balancing Operating Reserve Reliability Charges	\$49.1	\$27.8	(\$21.3)	34.6%	36.5%
Balancing Operating Reserve Deviation Charges	\$91.6	\$47.742	(\$43.9)	64.5%	62.7%
Balancing Operating Reserve Charges for Load Response	\$0.0	\$0.0	(\$0.0)	0.0%	0.0%
Balancing Local Constraint Charges	\$1.2	\$0.6	(\$0.6)	0.9%	0.8%
Total	\$141.9	\$76.1	(\$65.8)	100.0%	100.0%

²⁴ 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.

²⁵ See the *2022 Annual State of the Market Report for PJM*, Volume 2: Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-16 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 the first nine months of 2023, energy lost opportunity cost deviation charges decreased by \$8.7 million or 34.0 percent, and make whole deviation charges decreased by \$35.2 million or 53.3 percent compared to the same time period in 2022.

Table 4-16 Balancing operating reserve deviation charges: January through September, 2022 and 2023

Charge Attributable To	(Jan - Sep)	(Jan - Sep)	Change (Millions)	(Jan - Sep)	(Jan - Sep)
	2022 Charges (Millions)	2023 Charges (Millions)		2022 Share	2023 Share
Make Whole Payments to Generators and Imports	\$66.0	\$30.8	(\$35.2)	72.0%	64.6%
Energy Lost Opportunity Cost	\$25.6	\$16.9	(\$8.7)	28.0%	35.4%
Canceled Resources	\$0.0	\$0.0	\$0.0	0.0%	0.0%
Total	\$91.6	\$47.7	(\$43.9)	100.0%	100.0%

Table 4-17 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by \$0.7 million or 59.2 percent in the first nine months of 2023, compared to the same time period in 2022.

Table 4-17 Additional energy uplift charges: January through September, 2022 and 2023

Type	(Jan - Sep)	(Jan - Sep)	Change (Millions)	(Jan - Sep)	(Jan - Sep)
	2022 Charges (Millions)	2023 Charges (Millions)		2022 Share	2023 Share
Reactive Services Charges	\$1.2	\$0.5	(\$0.7)	77.6%	65.7%
Synchronous Condensing Charges	\$0.0	\$0.0	\$0.0	0.0%	0.0%
Black Start Services Charges	\$0.4	\$0.3	(\$0.1)	22.4%	34.3%
Total	\$1.6	\$0.8	(\$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 4-18 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.²⁶

Table 4-18 Composition of charges

Charge	Rate	Transaction / Resource Type								
		Load	Generation	Imports 1	Exports 1	Wheels	Economic			UTCs
						DR	INCs	DECs		
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	X
	Regional (East or West) Deviation Rate	X	X	X	X	X	X	X	X	X
	LOC Rate	X	X	X	X	X	X	X	X	
	Canceled Resources Rate	X	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.

Table 4-19 shows the average rates for each region in each charge category for the first nine months of 2022 and 2023. The average day-ahead rate in the first nine months of 2023 was 0.056 \$/MWh, with a minimum rate of 0.00 \$/MWh and a maximum rate of 0.428 \$/MWh. The average rate for the first nine months of 2023 is 0.006 \$/MWh higher than the average day-ahead rate in the first nine months of 2022.

The average RTO reliability rate in the first nine months of 2023 was 0.038 \$/MWh, with a minimum rate of 0.000 \$/MWh and a maximum rate of 0.228 \$/MWh. The average RTO reliability rate in the first nine months of 2023 is 0.030 \$/MWh lower than the average rate in the first nine months of 2022.

The average RTO deviation rate in the first nine months of 2023 was 0.085 \$/MWh, with a minimum rate of 0.000 \$/MWh and a maximum rate of 0.641 \$/MWh. The average RTO deviation rate in the first nine months of 2023 is 0.152 \$/MWh lower than the average rate in the first nine months of 2022.

²⁶ 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.

Table 4-19 Operating reserve rates (\$/MWh): January through September, 2022 and 2023

Rate	Avg 2022 (Jan - Sep) (\$/MWh)	Min 2022 (Jan - Sep) (\$/MWh)	Max 2022 (Jan - Sep) (\$/MWh)	Avg 2023 (Jan - Sep) (\$/MWh)	Min 2023 (Jan - Sep) (\$/MWh)	Max 2023 (Jan - Sep) (\$/MWh)	Difference of Avg (\$/MWh)	Percent Difference of Avg
Day-Ahead	0.050	(0.000)	0.354	0.056	(0.000)	0.428	0.006	11.8%
Day-Ahead with Unallocated Congestion	0.050	(0.000)	0.354	0.056	(0.000)	0.428	0.006	11.8%
RTO Reliability	0.068	0.000	0.977	0.038	0.000	0.228	(0.030)	(44.5%)
East Reliability	0.021	0.000	0.451	0.015	0.000	0.330	(0.006)	(27.3%)
West Reliability	0.002	0.000	0.110	0.001	0.000	0.106	(0.000)	(2.3%)
RTO Deviation	0.236	(0.000)	1.981	0.085	(0.000)	0.641	(0.152)	(64.2%)
East Deviation	0.156	0.000	2.951	0.046	0.000	0.681	(0.110)	(70.3%)
West Deviation	0.007	0.000	0.482	0.006	0.000	0.164	(0.000)	(4.7%)
Lost Opportunity Cost	0.120	0.000	3.803	0.061	0.000	1.102	(0.060)	(49.7%)
Canceled Resources	0.000	0.000	0.000	0.000	0.000	0.000	NA	NA
Dispatch Differential Lost Opportunity Cost	0.004	0.000	0.036	0.001	0.000	0.005	NA	NA

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.²⁷ 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 4-20 shows the reactive services rates associated with local voltage support in the first nine months of 2022 and 2023. Table 4-20 shows that in the first nine months of 2023 no zones incurred reactive services charges.

Table 4-20 Local voltage support rates: January through September, 2022 and 2023

Control Zone	(Jan - Sep) 2022 (\$/MWh)	(Jan - Sep) 2023 (\$/MWh)	Difference (\$/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.001	0.001	NA
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.011	0.017	0.006	52.0%
COMED	0.000	0.000	0.000	0.0%
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	0.002	0.000	(0.002)	(100.0%)
DPL	0.016	0.000	(0.016)	(100.0%)
EKPC	0.000	0.000	0.000	0.0%
JCPLC	0.000	0.000	0.000	0.0%
MEC	0.001	0.000	(0.001)	(100.0%)
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	0.023	0.000	(0.023)	(100.0%)
PPL	0.000	0.000	0.000	0.0%
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

²⁷ See 2022 Annual State of the Market Report for PJM, Volume 2; Section 10: Ancillary Service Markets.

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 4-21 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.²⁸ 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.²⁹

Table 4-21 Dispatch status, commitment status and uplift eligibility³⁰

Dispatch Status	Dispatch Description	Commitment Status	
		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

²⁸ PJM has modified the basic rules of eligibility to set price using its CT price setting logic.

²⁹ 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.

³⁰ PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

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.³¹ Since 2018, the cumulative resettlement requests total \$15.3 million, of which PJM has agreed and resettled 9.0 percent over the last two years, and 4.0 percent remain pending. The remaining 75.5 percent occurred prior to September 2021 and is subject to the OATT's limitation on claims, but that limit does not apply if PJM informed the market participant within two years of the issue.³² PJM should inform market participants of a potential issue when the MMU raises the issue with PJM and the market participant in order to ensure that the issues can be addressed. 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.

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).³³ 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 4-22 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first nine months of 2023, balancing operating reserve credits would have been \$12.5 million or 21.5 percent lower if they were calculated on a daily basis. In the first nine months of 2022, balancing operating reserve credits would have been \$30.4 million or 26.9 percent lower if they were calculated on a daily basis.

Table 4-22 Intraday segments and daily balancing operating reserve credits: January 2022 through September 2023

	2022 Balancing Generator Credits (Millions)			2023 Balancing Generator Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	\$10.1	\$8.4	(\$1.7)	\$4.0	\$3.2	(\$0.8)
Feb	\$3.2	\$2.5	(\$0.7)	\$3.5	\$3.0	(\$0.4)
Mar	\$5.3	\$4.4	(\$0.8)	\$4.2	\$3.5	(\$0.8)
Apr	\$11.5	\$9.7	(\$1.8)	\$10.6	\$8.8	(\$1.9)
May	\$10.5	\$7.9	(\$2.6)	\$9.4	\$7.4	(\$2.0)
Jun	\$13.8	\$9.8	(\$4.0)	\$5.3	\$3.9	(\$1.3)
Jul	\$20.3	\$14.6	(\$5.7)	\$8.7	\$6.4	(\$2.2)
Aug	\$26.7	\$18.9	(\$7.8)	\$5.1	\$3.6	(\$1.5)
Sep	\$11.5	\$6.3	(\$5.3)	\$7.3	\$5.6	(\$1.6)
Oct	\$8.7	\$6.6	(\$2.2)			
Nov	\$11.9	\$9.8	(\$2.1)			
Dec	\$46.8	\$40.3	(\$6.5)			
Total (Jan - Sep)	\$112.9	\$82.5	(\$30.4)	\$58.1	\$45.6	(\$12.5)

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 4-23

³¹ To date, the MMU has only requested resettlement of the most egregious cases.

³² OATT § 10.4.

³³ See PJM "Manual 28: Operating Reserve Accounting," Rev. 92 (July 26, 2023).

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 the first nine months of 2023, LOC credits would have been \$1.7 million or 11.2 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In the first nine months of 2023, LOC credits would have been \$4.9 million or 31.4 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

Table 4-23 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through September, 2023

2023 Day-Ahead LOC Credits (Millions)					
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	\$1.9	\$1.7	(\$0.2)	\$1.5	(\$0.4)
Feb	\$0.6	\$0.5	(\$0.1)	\$0.3	(\$0.3)
Mar	\$0.6	\$0.6	(\$0.1)	\$0.4	(\$0.2)
Apr	\$1.3	\$1.4	\$0.1	\$1.1	(\$0.2)
May	\$1.5	\$1.2	(\$0.2)	\$1.0	(\$0.5)
Jun	\$1.1	\$0.9	(\$0.2)	\$0.7	(\$0.5)
Jul	\$4.2	\$3.7	(\$0.5)	\$2.7	(\$1.5)
Aug	\$2.2	\$1.9	(\$0.3)	\$1.7	(\$0.6)
Sep	\$2.0	\$1.8	(\$0.2)	\$1.2	(\$0.8)
Total (Jan - Sep)	\$15.5	\$13.8	(\$1.7)	\$10.6	(\$4.9)

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.³⁴

Table 4-24 shows the concentration of energy uplift credits. The top 10 units received 41.4 percent of total energy uplift credits in the first nine months of 2023, compared to 26.7 percent in the same time period in 2022. The top 10

³⁴ 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.

companies received 72.4 percent of total energy uplift credits in the first nine months of 2023.

Table 4-24 Top 10 units and organizations energy uplift credits: January through September, 2023

Category	Type	Top 10 Units		Top 10 Organizations	
		Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	\$40.9	95.6%	\$42.4	99.2%
	Canceled Resources	\$0.1	100.0%	\$0.1	100.0%
Balancing	Generators	\$9.4	16.1%	\$40.1	69.1%
	Local Constraints Control	\$0.4	77.1%	\$0.6	100.0%
	Lost Opportunity Cost	\$5.4	31.9%	\$12.6	74.6%
	Dispatch Differential Lost Opportunity Cost	\$0.1	17.6%	\$0.3	67.6%
	Total Balancing	\$15.3	20.1%	\$53.7	70.6%
Reactive Services		\$0.5	100.0%	\$0.5	100.0%
Synchronous Condensing		\$0.0	NA	\$0.0	NA
Black Start Services		\$0.1	38.8%	\$0.2	92.6%
Total		\$49.5	41.4%	\$89.8	75.1%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-25 through Table 4-29 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Table 4-25 Top 10 recipients of total uplift: January through September, 2023

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	\$18,380,596	15.4%
2	BC BRANDON SHORES 1 F	BGE	\$14,266,877	11.9%
3	PEP CHALKPOINT 3 F	PEPCO	\$5,582,251	4.7%
4	PEP CHALKPOINT 4 F	PEPCO	\$3,057,019	2.6%
5	BC WAGNER 4 F	BGE	\$2,821,427	2.4%
6	BC WAGNER 3 F	BGE	\$1,497,816	1.3%
7	VP LOUISA 5 CT	DOM	\$1,215,054	1.0%
8	VP FOUR RIVERS 1 CT	DOM	\$933,011	0.8%
9	VP DOSWELL 2 CT	DOM	\$918,540	0.8%
10	VP MARSHRUN 1 CT	DOM	\$815,287	0.7%
Total of Top 10			\$49,487,876	41.4%
Total Uplift Credits			\$119,632,478	100.0%

Table 4-26 Top 10 recipients of day-ahead generation credits: January through September, 2023

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	\$16,006,763	37.4%
2	BC BRANDON SHORES 1 F	BGE	\$12,786,898	29.9%
3	PEP CHALKPOINT 3 F	PEPCO	\$4,991,619	11.7%
4	PEP CHALKPOINT 4 F	PEPCO	\$2,906,585	6.8%
5	BC WAGNER 4 F	BGE	\$2,101,685	4.9%
6	BC WAGNER 3 F	BGE	\$1,118,600	2.6%
7	BC WAGNER 1 F	BGE	\$397,647	0.9%
8	DPL WILDCAT POINT 1 CC	DPL	\$207,926	0.5%
9	PL BRUNNER ISLAND 3 F	PPL	\$204,509	0.5%
10	PL MONTOUR 2 F	PPL	\$168,703	0.4%
Total of Top 10			\$40,890,935	95.6%
Total day-ahead operating reserve credits			\$42,770,718	100.0%

Table 4-27 Top 10 recipients of balancing generator credits: January through September, 2023

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	BC BRANDON SHORES 2 F	BGE	\$1,936,682	3.3%
2	BC BRANDON SHORES 1 F	BGE	\$1,479,953	2.5%
3	VP LOUISA 5 CT	DOM	\$910,380	1.6%
4	VP FOUR RIVERS 1 CT	DOM	\$831,719	1.4%
5	VP MARSHRUN 1 CT	DOM	\$767,421	1.3%
6	VP DOSWELL 2 CT	DOM	\$734,299	1.3%
7	BC WAGNER 4 F	BGE	\$719,742	1.2%
8	VP MARSHRUN 3 CT	DOM	\$710,900	1.2%
9	DEOK WOODSDALE 5 CT	DUKE	\$636,247	1.1%
10	VP DOSWELL 3 CT	DOM	\$624,737	1.1%
Total of Top 10			\$9,352,080	16.1%
Total balancing operating reserve credits			\$58,050,594	100.0%

Table 4-28 Top 10 recipients of lost opportunity cost credits: January through September, 2023

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	DPL DEMEC - CLAYTON 2 CT	DPL	\$779,612	4.6%
2	DPL DEMEC - CLAYTON 1 CT	DPL	\$753,754	4.5%
3	AEP ANDERSON 3 CT	AEP	\$603,322	3.6%
4	FE LEMOYNE 3 CT	ATSI	\$581,139	3.4%
5	FE LEMOYNE 2 CT	ATSI	\$547,740	3.2%
6	FE LEMOYNE 1 CT	ATSI	\$480,981	2.8%
7	FE LEMOYNE 4 CT	ATSI	\$477,478	2.8%
8	DPL COMM CHESAPEAKE - NEW CHURCH 1 CT	DPL	\$474,120	2.8%
9	DPL COMM CHESAPEAKE - NEW CHURCH 2 CT	DPL	\$366,796	2.2%
10	DPL COMM CHESAPEAKE - NEW CHURCH 4 CT	DPL	\$327,331	1.9%
Total of Top 10			\$5,392,274	31.9%
Total lost opportunity cost credits			\$16,912,370	100.0%

Table 4-29 Top 10 recipients of dispatch differential lost opportunity cost credits: January through September, 2023

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP GAVIN 1 F	AEP	\$15,852	3.1%
2	AEP GAVIN 2 F	AEP	\$9,731	1.9%
3	DPL KENT 2 CT	DPL	\$9,533	1.9%
4	PL HUMMEL STATION 1 CC	PPL	\$8,629	1.7%
5	VP FOUR RIVERS 60 CC	DOM	\$8,489	1.7%
6	VP FOUR RIVERS 50 CC	DOM	\$8,085	1.6%
7	COM 935 KENDALL 2 CC	COMED	\$8,063	1.6%
8	VP PANDA STONEWALL 1 CC	DOM	\$7,342	1.4%
9	COM 935 KENDALL 4 CC	COMED	\$7,252	1.4%
10	COM 935 KENDALL 1 CC	COMED	\$7,235	1.4%
Total of Top 10			\$90,212	17.6%
Total dispatch differential lost opportunity cost credits			\$512,290	3.0%

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.³⁵ 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 4-30 shows the uplift credits paid to committed and dispatched units in the first nine months of 2023 by offer type. Units received \$36.2 million or 62.3 percent of balancing generator credits and \$4.6 million or 10.8 percent of day-ahead operating reserve credits in the first nine months of 2023 using price-based offers. Units received \$16.7 million or 28.7 percent of balancing generator credits and \$37.6 million or 87.8 percent of day-ahead operating reserves in the first nine months of 2023 using cost-based offers.

Table 4-30 Operating Reserve Credits by Offer Type: January through September, 2023

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total	Share of Total Uplift
Cost	\$37.6	\$16.7	\$0.4	\$0.0	\$54.7	45.7%
Price	\$4.6	\$36.2	\$0.0	\$0.0	\$40.8	34.1%
Price PLS	\$0.6	\$3.9	\$0.0	\$0.0	\$4.5	3.8%
Cost & Price	\$0.0	\$1.1	\$0.0	\$0.0	\$1.1	0.9%
Cost & PLS	\$0.0	\$0.1	\$0.0	\$0.0	\$0.1	0.1%
Price & PLS	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	0.0%
Total	\$42.8	\$58.0	\$0.5	\$0.0	\$101.3	84.7%
Share	42.2%	57.3%	0.5%	0.0%	100.0%	NA

Table 4-31 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, 86.4 percent went to units that were committed on cost schedules, which are parameter limited, 2.9 percent went to units that were committed on price PLS schedules and 10.3 percent went to units committed on price schedules less flexible than PLS. The 10.3 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 4-31 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through September, 2023

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
COST CAPPED Committed on cost (cost capped)	\$23,857,863	86.4%
PRICE NONPLS FLEXIBLE Committed on price schedule as flexible as PLS	\$116,988	0.4%
PRICE NONPLS INFLEXIBLE Committed on price schedule less flexible than PLS	\$2,830,741	10.3%
PRICE PLS COMMITTED Committed on price PLS	\$805,170	2.9%
Total	\$27,610,761	100.0%

³⁵ 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>.

Gas fired generators may request temporary exceptions to parameter limits such as minimum run time based on restrictions imposed by natural gas pipelines, including ratable takes.³⁶ Table 4-32 shows the uplift credits received by units that submitted parameter exception requests for a 24 hour minimum run time based on gas pipeline restrictions. In the first nine months of 2023, units that requested an exception for 24 hour minimum run time received \$7.9 million of day ahead operating reserves, or 18.5 percent of total day-ahead operating reserves and 6.6 percent of total uplift. During the same time period, units that requested an exception for 24 hour minimum run time received \$0.7 million in balancing generator credits, or 2.1 percent of total balancing generator credits and 1.0 percent of total uplift credits.

Table 4-32 Uplift credits for units with 24 hour minimum run times due to gas pipeline restrictions: January through September, 2023

	Day-Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Lost Opportunity Cost Credits (Millions)	Total Credits (Millions)
	\$7.9	\$1.2	\$0.0	\$9.1
Share of Uplift Category	18.5%	2.1%	0.2%	7.6%
Share of Total Uplift	6.6%	1.0%	0.0%	7.6%

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 the first nine months of 2023 was \$0.5 million. Table 4-5 shows that 42.1 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 26.9 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 4-33 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received \$14.9 million in balancing generator credits, or 25.7 percent of total balancing operating reserves. Fast start units received \$2.1 million in day-ahead lost opportunity costs, or 6.7 percent of all lost

³⁶ See OA Schedule 1 Section 6.6 (C) Minimum Generator Operating Parameters – Parameter Limited Schedules

opportunity costs. Fast start units received less than \$0.001 million in day-ahead operating credits, or less than 0.1 percent of total day-ahead operating reserve credits.

Table 4-33 Monthly day-ahead operating reserves, balancing generator credits, and day-ahead lost opportunity cost credits for fast start units: January through September, 2023

Month	Day-Ahead Operating Reserves (Millions)	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits (Millions)	Share of Monthly Balancing Generator Credits	Day Ahead Lost Opportunity Cost Credits (Millions)	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	\$0.0	0.1%	\$1.1	28.6%	\$0.3	13.3%
Feb	\$0.0	0.0%	\$0.7	19.3%	\$0.2	32.8%
Mar	\$0.0	0.2%	\$1.1	26.4%	\$0.1	10.1%
Apr	\$0.0	0.1%	\$2.6	24.5%	\$0.1	5.4%
May	\$0.0	0.1%	\$3.2	33.6%	\$0.2	12.4%
Jun	\$0.0	0.3%	\$1.6	30.5%	\$0.1	10.0%
Jul	\$0.0	0.0%	\$1.8	21.2%	\$0.7	16.8%
Aug	\$0.0	0.0%	\$1.3	24.5%	\$0.2	10.4%
Sep	\$0.0	0.0%	\$1.5	20.7%	\$0.3	15.9%
Total (Jan - Sep)	\$0.0	0.0%	\$14.9	25.7%	\$2.1	13.8%

Table 4-34 shows the day-ahead, balancing generator credits, and day-ahead lost opportunity cost credits for combustion turbines by month, also included in Table 4-33.

Table 4-34 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: January through September, 2023

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits	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	0.1%	\$1.1	27.1%	\$0.2	10.8%
Feb	\$0.0	0.0%	\$0.6	18.4%	\$0.1	24.9%
Mar	\$0.0	0.2%	\$1.1	25.3%	\$0.1	8.7%
Apr	\$0.0	0.1%	\$2.6	24.2%	\$0.1	5.2%
May	\$0.0	0.1%	\$3.1	33.3%	\$0.2	11.9%
Jun	\$0.0	0.3%	\$1.6	30.4%	\$0.1	7.7%
Jul	\$0.0	0.0%	\$1.8	20.8%	\$0.6	13.9%
Aug	\$0.0	0.0%	\$1.2	23.9%	\$0.2	9.5%
Sep	\$0.0	0.0%	\$1.5	20.0%	\$0.3	14.9%
Total (Jan - Sep)	\$0.0	0.0%	\$14.7	25.4%	\$1.9	12.5%

