Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources to operate for the PJM system at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost 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 operators. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges, and are treated for uplift purposes as being equivalent to a decrement bid (DEC) at the sink point of the UTC.[2]

Uplift is an inherent part of the PJM market design. Part of that 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.[3] [4] 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 incorporates efficient prices with minimal uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

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.[5]

Overview

Energy Uplift Credits

- **Types of credits.** In the first three months of 2021, energy uplift credits were $34.4 million, including $4.5 million in day-ahead generator credits, $20.4 million in balancing generator credits, $4.5 million in lost opportunity cost credits, and $4.2 million in local constraint control credits.
- **Types of units.** In the first three months of 2021, coal units received 75.5 percent of day-ahead generator credits, and combustion turbines received 92.8 percent of balancing generator credits and 98.4 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first three months of 2021, 88.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 60.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first three months of 2021, 0.2 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 74.6 percent received energy uplift payments.

1 Loss exists 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.

2 See 172 FERC ¶ 61,046 (2020).

3 *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).

4 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.

5 Demand response payments are addressed in Section 6: Demand Response.

- **Concentration of Energy Uplift Credits.** In the first three months of 2021, the top 10 units receiving energy uplift credits received 27.9 percent of all credits and the top 10 organizations received 79.5 percent of all credits. The HHI for day-ahead operating reserves was 7592, the HHI for balancing operating reserves was 3402 and the HHI for lost opportunity cost was 7044, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $3.0 million or 191.0 percent, in the first three months of 2021 compared to the first three months of 2020, from $1.5 million to $4.5 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 99.5 percent of the $4.5 million. The day-ahead generation paid LOC credits for this reason decreased by 130.5 GWh or 73.6 percent during 2021, compared to 2020, from 177.4 GWh to 46.9 GWh.
- **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 proper offer parameters. Since 2018, the MMU has made cumulative resettlement requests for overpaid units that total $12.1 million, of which PJM has resettled 11.4 percent.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $27.2 million, or 378.5 percent, in the first three months of 2021 compared to the first three months of 2020, from $7.2 million to $34.4 million.
- **Energy Uplift Charges Categories.** The increase of $27.2 million in the first three months of 2021 was comprised of a $4.2 million increase in day-ahead operating reserve charges, a $22.3 million increase in balancing operating reserve charges, and a $0.7 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.020 per MWh, real-time load paid $0.067 per MWh, DECs and UTCs paid $0.265 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.245 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.020 per MWh, real-time load paid $0.053 per MWh, DECs and UTCs paid $0.225 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.205 per MWh in the first three months of 2021.
- **Reactive Services Rates.** PPL was the only zone with local voltage support rates, excluding reactive capability payments. PPL had a rate of $0.064 per MWh.

Geography of Charges and Credits

- In the first three months of 2021, 87.6 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.2 percent by transactions at hubs and aggregates, and 9.2 percent by transactions at interchange interfaces.
- In the first three months of 2021, generators in the Eastern Region received 55.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2021, generators in the Western Region received 41.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2021, external generators received 2.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)

- The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the day-ahead energy market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Partially adopted, 2019.)
- The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations. (Priority: Medium. First reported 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2020. 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 enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead uplift, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift 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. Stakeholder process.)
- 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 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 eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[6])
- The MMU recommends allocating the energy uplift payments to units scheduled 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.)

6 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Volume II, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the day-ahead and the real-time energy markets and the associated operating reserve 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 operating reserves. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift (operating reserve) confidentiality rules in order to allow the disclosure of complete information about the level of uplift (operating reserve charges) by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[7])
- 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 that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Not adopted.)

Conclusion

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

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus start up and no load costs. 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

7 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 March 21, 2019. 166 FERC ¶ 61,210. PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

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.

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 and of convex hull 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 will be created by PJM's fast start pricing proposal (limited convex hull pricing). Fast start pricing has been approved by FERC subject to a PJM compliance filing on the definition of fast start resources, and is expected to be implemented in 2021.[8] Fast start pricing will affect uplift calculations.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[9] 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.

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[10] The uplift payments for UTCs began on November 1, 2020.[11]

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 local reserve zones or 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. they 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

8 See 173 FERC ¶ 61,244 (2020).

9 On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 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.

10 See 172 FERC ¶ 61,046.

11 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).

on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make these units ineligible for uplift credits. Since 2018, the MMU has identified $12.1 million of incorrect uplift credits.

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.

Energy Uplift Credits Results

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. The resulting costs not covered by energy revenues are collected as energy uplift.

Table 4-1 shows the totals for each credit category for the first three months of 2020 and 2021.[12] In the first three months of 2021, energy uplift credits increased by $27.2 million or 378.5 percent compared to the first three months of 2020.

Table 4-1 Energy uplift credits by category: January through March, 2020 and 2021[13]

Category	Type	(Jan - Mar) 2020 Credits (Millions)	(Jan - Mar) 2021 Credits (Millions)	Change	Percent Change	2020 Share	2021 Share
Day-Ahead	Generators	$0.3	$4.5	$4.2	1,378.4%	4.3%	13.1%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	NA	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$3.2	$20.4	$17.2	545.1%	44.0%	59.2%
	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	$2.1	$4.2	$2.1	102.0%	29.1%	12.3%
	Lost Opportunity Cost	$1.6	$4.5	$3.0	191.0%	21.5%	13.1%
Reactive Services	Day-Ahead	$0.0	$0.3	$0.3	7,776.2%	0.0%	0.8%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Reactive Services	$0.0	$0.4	$0.4	948.4%	0.6%	1.3%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.0	$0.1	$0.0	NA	0.6%	0.2%
Total		$7.2	$34.4	$27.2	378.5%	100.0%	100.0%

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 12, 2021.

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

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for 2020 and 2021. Uplift credits increased for most unit types, with the exception of wind units. A combination of factors led to increased uplift payments in the first three months of 2021, including higher natural gas prices, increased load due to winter weather in the first three months of 2021, and new operational behavior by CTs in the balancing market. Higher natural gas prices increased the costs of gas units and resulted in increased make whole payments to combustion turbines and increased coal generation. Coal units had the largest percent increase in uplift credits, with an increase of $3.8 million or 1,309.0 percent in the first three months of 2021 compared with the same period in 2020. This increase can largely be attributed to a small number of coal units in the BGE, PEPCO, and DPL Zones. Combustion turbines had the largest change in uplift credits with an increase of $22.3 million or 366.6 percent.

In the first three months of 2021, uplift credits to wind units were $0.1 million, down by 17.4 percent compared to the first three months of 2020.

Table 4-2 Total energy uplift credits by unit type: January through March, 2020 and 2021[14] [15]

Unit Type	(Jan - Mar) 2020 Credits (Millions)	(Jan - Mar) 2021 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2020 Share	(Jan - Mar) 2021 Share
Combined Cycle	$0.7	$1.4	$0.7	114.1%	9.1%	4.1%
Combustion Turbine	$6.1	$28.3	$22.3	366.6%	84.4%	82.3%
Diesel	$0.1	$0.4	$0.3	264.2%	1.5%	1.1%
Hydro	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Nuclear	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$0.3	$4.1	$3.8	1,309.0%	4.0%	11.8%
Steam - Other	$0.0	$0.2	$0.2	4,870.9%	0.0%	0.5%
Wind	$0.064	$0.052	($0.0)	(17.4%)	0.9%	0.2%
Total	$7.2	$34.4	$27.2	378.6%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first three months of 2021. The characteristics of the different unit types explain why uplift in specific categories is paid primarily to specific unit types. For example, the majority of day-ahead credits, 78.3 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 credits. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real-time market, received 92.8 percent of balancing credits and 94.9 percent of lost opportunity credits. Combustion turbines committed in the real-time market tend to require balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines with a day-ahead schedule and not committed in real time receive lost opportunity credits when they incur a loss as a result of not operating. A unit incurs a loss when the real-time LMPs are greater than the day-ahead LMPs at the unit's pricing node and the unit's balancing charges are greater than its day-ahead revenues.

Table 4-3 Energy uplift credits by unit type: January through March, 2021

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	18.2%	2.6%	0.0%	0.0%	0.8%	0.0%	0.0%	24.9%
Combustion Turbine	3.5%	92.8%	0.0%	100.0%	94.9%	100.0%	0.0%	75.1%
Diesel	0.0%	1.2%	0.0%	0.0%	3.5%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	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%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	75.5%	3.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Steam - Other	2.8%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
Total (Millions)	$4.5	$20.4	$0.0	$4.2	$4.5	$0.7	$0.0	$0.1

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.

Day-Ahead Unit Commitment for Reliability

PJM may 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 reactive transfer interface control needed to maintain system reliability in a zone or reactive service.[16] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[17] 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 4-4 shows total day-ahead generation and the subset of that generation committed for reliability by PJM. There was a significant increase in the day-ahead generation committed for reliability by PJM, from 11 MW in the first three months of 2020 to 317 MW in the first three months of 2021. The increase in day-ahead generation committed for reliability by PJM was due to an increased need to commit uneconomic units in the BGE, PEPCO, and DPL Zones for reliability. Delayed transmission maintenance during the COVID 19 pandemic increased the transmission outages in the first three months of 2021, resulting in an increased need for reliability commitments.

Table 4-4 Day-ahead generation committed for reliability (GWh): January through March, 2020 and 2021

	2020			2021		
	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	71,116	0	0.0%	73,635	95	0.1%
Feb	65,827	5	0.0%	71,354	13	0.0%
Mar	63,058	6	0.0%	64,713	209	0.3%
Total (Jan - Mar)	200,001	11	0.0%	209,702	317	0.2%

Pool scheduled units and units committed for reliability are made whole in the day-ahead energy market if their total 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 three months of 2021 were $4.5 million. The top 10 units received $3.8 million or 83.3 percent of all day-ahead operating reserve credits. These units were large units with long commitment times and inflexible operating parameters.

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 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In the first three months of 2021, 74.6 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 72.0 percent paid as day-ahead operating reserve credits and 2.6 percent paid as reactive services credits. The remaining 25.4 percent was economic, meaning prices covered all resource operating costs and the unit did not receive operating reserve credits.

16 See OA Schedule 1 § 3.2.3(b).
17 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 16, 2018) at 33, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through March, 2021

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	7.0	44.3	43.2	94.6
Feb	1.3	4.1	7.5	12.9
Mar	0.0	179.6	29.5	209.1
Total (Jan - Mar)	8.3	228.0	80.2	316.5
Share	2.6%	72.0%	25.4%	100.0%

Total day-ahead operating reserve credits in the first three months of 2021 were $4.5 million, of which $2.6 million or 56.8 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. An additional 5.8 percent, or $0.3 million, was paid to units scheduled to provide reactive services.

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources operating at PJM's request that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits) and its real-time costs (startup, no load, and energy offer). Combustion turbines (CTs) received $18.8 million or 92.8 percent of all balancing operating reserve (BOR) credits in 2020. The majority of these credits, 98.7 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[18] 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. Units are disqualified from receiving uplift when the PJM dispatcher is able to identify units that are not following the dispatch signals, and after agreement with the generator, the dispatch reason is changed to self scheduled. PJM dispatchers should not be forced to decide which units qualify for uplift.

18 Operating outside 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.

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

Balancing operating reserve credits for generators increased by 545.1 percent in the first three months of 2021 compared to the first three months of 2020. Rising natural gas prices contributed to increased LMPs and higher balancing operating reserve credits during the first three months of 2021. The overall increase in credits in the DOM and AEP Zones accounted for 42.6 percent of the total annual change in balancing operating reserve credits.

The credits paid to combustion turbines committed in real time without a day-ahead commitment occurs despite the fact that the total combustion turbine MW committed in the day-ahead energy market are similar to the totals in the real-time energy market. Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In the first three months of 2021, generation by combustion turbines was 41.2 percent higher in the real-time energy market than in the day-ahead energy market, although this varied by month. Table 4-6 shows that only 4.7 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 57.3 percent of generation from combustion turbines in the real-time market was uneconomic and required $18.8 million in BOR credits. This increase in uneconomic real-time generation resulted in increased BOR credits during the first three months of 2021.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through March, 2021

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)	Generation Difference as a Percent of Real-Time Generation
Jan	240	6.5%	$0.0	483	62.7%	$4.4	50.3%
Feb	298	5.8%	$0.1	485	57.4%	$9.9	38.6%
Mar	309	2.1%	$0.1	471	51.6%	$4.5	34.5%
Total (Jan - Mar)	847	4.7%	$0.2	1,440	57.3%	$18.8	41.2%

An analysis of real-time generation by combustion turbines shows that BOR credits are incurred primarily by combustion turbines operating without or outside a day-ahead schedule.

Table 4-7 and Table 4-8 show real-time generation by combustion turbines by day-ahead commitment status during the first three months of 2021 and 2020. CTs that operated on a day-ahead schedule during the first three months of 2021 constituted 38.4 percent of real-time generation by CTs, of which 37.5 percent was uneconomic in the real-time market and received $0.3 million in BOR credits. CTs that operated on a day-ahead schedule during the first three months of 2020 constituted 69.5 percent of real-time generation by CTs, of which 4.2 percent was uneconomic in the real-time market and received zero BOR credits.

In the first three months of 2021, 61.6 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 69.6 percent was uneconomic in the real-time market and received $18.4 million in BOR credits. In the first three months of 2020, 30.5 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 33.0 percent was uneconomic in the real-time market and received $2.8 million in BOR credits. During the first three months of 2021, real-time generation operating on a day-ahead schedule decreased significantly compared to the first three months of 2020, while real-time generation operating outside of a day-ahead schedule increased significantly. This shift of real-time generation operating on a day-ahead schedule to real-time generation operating outside of a day-ahead schedule is a significant source of the increase of BOR credits. Balancing operating reserves for real-time generation committed on a day-ahead schedule are calculated differently than for real-time generation committed outside of a day-ahead schedule, and this difference resulted in increased credits.

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; differences in interchange transactions; and behavior by other generators. 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 time scales used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: January through March, 2021

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	154	31.8%	44.2%	$0.1	330	68.2%	71.3%	$4.3
Feb	184	38.0%	32.3%	$0.2	301	62.0%	72.8%	$9.7
Mar	214	45.5%	37.1%	$0.1	257	54.5%	63.7%	$4.4
Total (Jan - Mar)	553	38.4%	37.5%	$0.3	887	61.6%	69.6%	$18.4

Table 4-8 Real-time generation by combustion turbines by day-ahead commitment: January through March, 2020

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	363	66.1%	3.8%	$0.0	186	33.9%	37.1%	$1.5
Feb	241	76.1%	4.3%	$0.0	76	23.9%	32.3%	$0.6
Mar	316	69.1%	4.8%	$0.0	141	30.9%	27.9%	$0.8
Total (Jan - Mar)	919	69.5%	4.2%	$0.0	403	30.5%	33.0%	$2.8

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 different scenarios. 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 is scheduled to operate in the day-ahead energy market, but it is not requested by PJM in real time. In this scenario the unit will receive a credit which covers any loss in the day-ahead financial position of the unit plus the balancing spot energy market position. This LOC will be referred to as day-ahead LOC.

Table 4-9 shows monthly day-ahead and real-time LOC credits in the first three months of 2020 and 2021. In the first three months of 2021, LOC credits increased by $3.0 million or 191.0 percent compared to the first three months of 2020. The increase of $3.0 million is comprised of a $3.0 million increase in day-ahead LOC and a less than $0.1 million decrease in real-time LOC. The increase in day-ahead LOC credits was the result of increased day-ahead generation by combustion turbines and diesels not requested by PJM in real-time.

In the first three months of 2021, wind units received less than $0.1 million of real-time LOC, down by 82.1 percent from the first three months of 2020. In the first three months of 2021, real-time LOC credits to wind units accounted for 60.8 percent of the uplift payments to wind units. Wind units in the AEP and COMED Zones received 100 percent of real-time lost opportunity cost credits to wind units.

Table 4-10 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and the subset of day-ahead generation receiving LOC credits. In the first three months of 2021, 12.5 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.7 percentage points lower than in the first three months of 2020. In the first three months of 2021 compared to the first three months of 2020, day-ahead generation by combustion turbines decreased 32.6 percent, day-ahead generation not requested in real time decreased by 50.9 percent, and day-ahead generation not requested in real time receiving lost opportunity costs decreased by 73.6 percent. 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 4-9 Monthly lost opportunity cost credits (Millions): January through March, 2020 and 2021

	2020			2021		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.5	$0.0	$0.5	$0.4	$0.0	$0.4
Feb	$0.4	$0.0	$0.4	$0.6	$0.0	$0.6
Mar	$0.6	$0.1	$0.6	$3.5	$0.0	$3.6
Total (Jan - Mar)	$1.5	$0.07	$1.5	$4.5	$0.05	$4.5
Share (Jan - Mar)	95.4%	4.6%	100.0%	98.9%	1.1%	100.0%

Table 4-10 Day-ahead generation from combustion turbines and diesels (GWh): January through March, 2020 and 2021

	2020			2021		
	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	873	171	73	486	70	17
Feb	653	114	49	507	54	13
Mar	729	103	55	527	66	17
Total (Jan - Mar)	2,255	388	177	1,520	191	47
Share (Jan - Mar)	100.0%	17.2%	7.9%	100.0%	12.5%	3.1%

Uplift Eligibility

In PJM, units can have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM as a result of the day-ahead and real-time market clearing while self scheduled units are committed by generation owners. Table 4-11 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[19] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may self schedule in day ahead to clear and then pool schedule 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 eligible for balancing operating reserve credits. 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.[20]

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

20 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.

Table 4-11 Dispatch status, commitment status and uplift eligibility[21]

			Commitment Status	
Dispatch Status	Dispatch Description	Eligible to Set LMP	Self Scheduled (units committed by the generation owner)	Pool Scheduled (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	No	Not eligible to receive uplift	Eligible to receive uplift
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	No	Not eligible to receive uplift	Eligible to receive uplift
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Yes	Only eligible to receive LOC credits if dispatched down by PJM	Eligible to receive uplift

Table 4-12 shows day-ahead and real-time generation by commitment and dispatch status.

Table 4-12 Day-ahead and real-time generation by offer status and eligibility to set LMP (GWh): January through March, 2021

	Self Scheduled			Pool Scheduled						
	Dispatchable	Economic Minimum	Block Loaded	Dispatchable	Economic Minimum	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	25,411	50,473	48,662	40,219	39,134	5,802	209,702	85,156	124,546	65,630
Share of Day-Ahead	12.1%	24.1%	23.2%	19.2%	18.7%	2.8%	100.0%	40.6%	59.4%	31.3%
Real-Time Generation	22,466	48,301	48,535	40,228	42,665	6,839	209,035	89,733	119,303	62,694
Share of Real-Time	10.7%	23.1%	23.2%	19.2%	20.4%	3.3%	100.0%	42.9%	57.1%	30.0%

Economic and Noneconomic Generation[22]

Economic generation includes units scheduled day ahead by PJM or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled to produce energy day ahead or produce energy in real time at an incremental offer higher than the LMP at the unit's bus. The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits whenever the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-13 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits as defined by PJM. In the first three months of 2021, 88.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 60.2 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest.

Table 4-13 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through March, 2021

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	75,491	9,665	85,156	88.7%	11.3%
Real-Time	45,652	30,121	75,772	60.2%	39.8%

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

22 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the entire day or segment. Table 4-14 shows the generation receiving day-ahead and balancing operating reserve credits. In the first three months of 2021, 1.4 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.1 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-14 Generation receiving operating reserve credits (GWh): January through March, 2021

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	85,156	1,190	1.4%
Real-Time	75,772	814	1.1%

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, such as not following dispatch, not having the correct commitment status, or not operating with proper offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases. Since 2018, the cumulative resettlement requests totaled $12.1 million. Of that amount, PJM has agreed and resettled 11.4 percent of the requests, 85.3 percent remains pending. The remaining 3.3 percent occurred prior to March 2019 and would now require a directive from FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

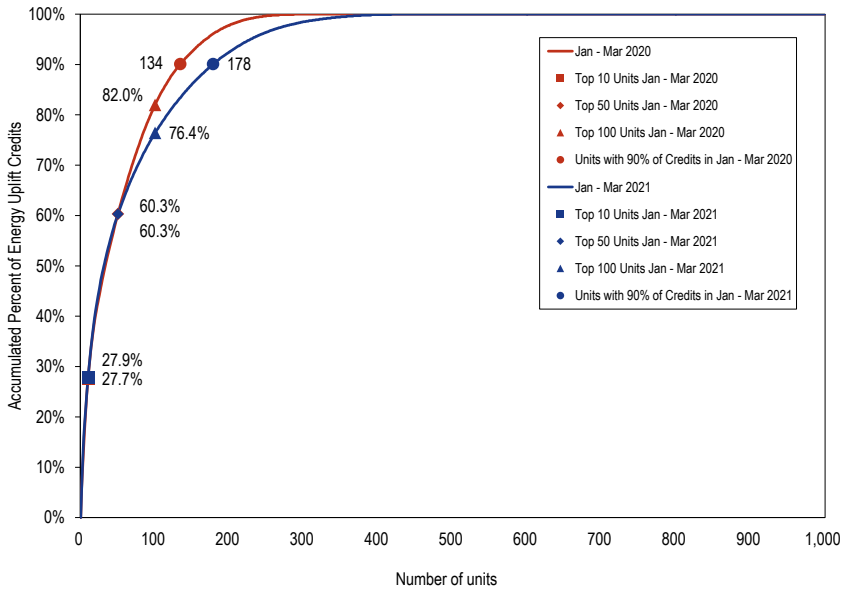
The MMU identifies units that are not following the dispatch signal, and that are therefore not eligible to receive uplift payments. These findings are communicated to PJM and/or Market Sellers. The units are identified by comparing their actual generation to the dispatch level that they should have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

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.[23]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 27.9 percent of total energy uplift credits in the first three months of 2021, compared to 27.7 percent in the first three months of 2020. In the first three months of 2021, 177 units received 90 percent of all energy uplift credits, compared to 133 units in the first three months of 2020.

Figure 4-1 Cumulative share of energy uplift credits: January through March, 2020 and 2021 by unit



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

Table 4-15 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in 2020.

Table 4-15 Top 10 units and organizations energy uplift credits: January through March, 2021

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$3.8	83.3%	$4.3	96.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$4.1	19.9%	$16.2	79.3%
	Local Constraints Control	$4.2	100.0%	$4.2	100.0%
	Lost Opportunity Cost	$3.1	69.2%	$4.2	93.6%
Reactive Services		$0.7	100.0%	$0.7	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	85.1%	$0.1	100.0%
Total		$9.6	27.9%	$27.3	79.5%

Table 4-16 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2021, 47.3 percent of all credits paid to these units were allocated to deviations while the remaining 52.7 percent were paid for reliability reasons.

Table 4-16 Balancing operating reserve credits to top 10 units by category and region: January through March, 2021

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$1.7	$0.4	$0.0	$1.3	$0.6	$0.0	$4.1
Share	42.7%	9.8%	0.2%	33.2%	13.9%	0.1%	100.0%

In the first three months of 2021, concentration in all energy uplift credit categories was high.[24] [25] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category.[26] Table 4-17 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 7592, for balancing operating reserve credits to generators was 3402, for lost opportunity cost credits was 7044 and for reactive services credits was 9777. All of these HHI values are characterized as highly concentrated.

Table 4-17 Daily energy uplift credits HHI: January through March, 2021

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7592	2823	10000	100.0%	44.7%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3402	1089	10000	100.0%	20.7%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	7044	1913	10000	100.0%	63.9%
Reactive Services		9777	5088	10000	100.0%	97.7%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9712	6475	10000	100.0%	24.8%
Total		2953	1052	9036	99.3%	15.3%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-18 through Table 4-21 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits. The top 10 units receiving uplift credits received 27.9 percent of all credits, with the top recipient receiving 4.8 percent. The top 10 units receiving day-ahead operating reserves received 83.3 percent. The top 10 recipients of balancing operating reserves received 19.9 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 69.2 percent of total lost opportunity cost credits.

24 See the *2020 State of the Market Report for PJM* Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
25 Table 4-16 excludes local constraint control categories.
26 Concentration is measured using the entity (or entities) to which the uplift credit is paid.

Table 4-18 Top 10 recipients of total uplift: January through March, 2021

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$1,651,072	4.8%
2	DAY GREENVILLE 1 CT	DAY	$1,439,330	4.2%
3	DAY GREENVILLE 4 CT	DAY	$1,301,389	3.8%
4	DAY GREENVILLE 3 CT	DAY	$1,173,233	3.4%
5	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$767,623	2.2%
6	PEP MORGANTOWN 1 F	PEPCO	$706,653	2.1%
7	VP LOUISA 5 CT	DOM	$683,982	2.0%
8	DPL INDIAN RIVER 4 F	DPL	$649,819	1.9%
9	VP MARSHRUN 2 CT	DOM	$627,762	1.8%
10	VP MARSHRUN 1 CT	DOM	$600,875	1.7%
Total of Top 10			$9,601,738	27.9%
Total Uplift Credits			$34,400,961	100.0%

Table 4-19 Top 10 recipients of day-ahead generation credits: January through March, 2021

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$1,542,458	34.1%
2	PEP MORGANTOWN 1 F	PEPCO	$697,476	15.4%
3	DPL INDIAN RIVER 4 F	DPL	$460,761	10.2%
4	VP BRUNSWICK 1CC	DOM	$280,850	6.2%
5	BC BRANDON SHORES 1 F	BGE	$254,942	5.6%
6	DPL WILDCAT POINT 1 CC	DPL	$213,120	4.7%
7	PL BRUNNER ISLAND 1 F	PPL	$161,282	3.6%
8	VP CLOVER 2 F	DOM	$74,295	1.6%
9	DPL VIENNA 8 F	DPL	$42,411	0.9%
10	PS BERGEN 2CC F	PSEG	$39,250	0.9%
Total of Top 10			$3,766,845	83.3%
Total day-ahead operating reserve credits			$4,521,870	100.0%

Table 4-20 Top 10 recipients of balancing operating reserve credits: January through March, 2021

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	VP LOUISA 5 CT	DOM	$670,278	3.3%
2	VP MARSHRUN 2 CT	DOM	$620,716	3.0%
3	VP MARSHRUN 1 CT	DOM	$593,343	2.9%
4	VP MARSHRUN 3 CT	DOM	$528,976	2.6%
5	VP FOUR RIVERS 1 CT	DOM	$332,490	1.6%
6	BC PERRYMAN 6 CT	BGE	$298,129	1.5%
7	FE LEMOYNE 1 CT	ATSI	$280,694	1.4%
8	VP DOSWELL 3 CT	DOM	$250,688	1.2%
9	EKPC JK SMITH 5 CT	EKPC	$245,337	1.2%
10	EKPC JK SMITH 7 CT	EKPC	$229,432	1.1%
Total of Top 10			$4,050,085	19.9%
Total balancing operating reserve credits			$20,381,544	100.0%

Table 4-21 Top 10 recipients of lost opportunity cost credits: January through March, 2021

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	DPL	$593,804	13.2%
2	DPL COMM CHESAPEAKE - NEW CHURCH 4 CT	DPL	$545,976	12.1%
3	DPL COMM CHESAPEAKE - NEW CHURCH 5 CT	DPL	$471,660	10.5%
4	DPL COMM CHESAPEAKE - NEW CHURCH 7 CT	DPL	$406,181	9.0%
5	DPL COMM CHESAPEAKE - NEW CHURCH 2 CT	DPL	$327,493	7.3%
6	DPL COMM CHESAPEAKE - NEW CHURCH 6 CT	DPL	$275,766	6.1%
7	DPL COMM CHESAPEAKE - NEW CHURCH 1 CT	DPL	$257,634	5.7%
8	VP LADYSMYTH 5 CT	DOM	$95,886	2.1%
9	FE LEMOYNE 1 CT	ATSI	$73,842	1.6%
10	AEP WOLF HILL 1 CT	AEP	$68,688	1.5%
Total of Top 10			$3,116,930	69.2%
Total lost opportunity cost credits			$4,502,987	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. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-22 and Table 4-23 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-22 Day-ahead and balancing operating reserve credits and charges

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

Table 4-23 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges increased by $27.2 million or 378.5 percent in the first three months of 2021 compared to the first three months of 2020.

Table 4-24 shows total energy uplift charges by category in the first three months of 2020 and the first three months of 2021.[27] The increase of $27.2 million is comprised of an increase of $4.2 million in day-ahead operating reserve charges, an increase of $22.3 million in balancing operating reserve charges and an increase of $0.7 million in reactive service charges.

Table 4-24 Total energy uplift charges by category: January through March, 2020 and 2021

Category	(Jan - Mar) 2020 Charges (Millions)	(Jan - Mar) 2021 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$0.3	$4.5	$4.2	1,376.4%
Balancing Operating Reserves	$6.8	$29.1	$22.3	328.2%
Reactive Services	$0.0	$0.7	$0.7	1,442.5%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.0	$0.1	$0.0	70.7%
Total	$7.2	$34.4	$27.2	378.5%
Energy Uplift as a Percent of Total PJM Billing	0.1%	0.3%	0.2%	273.2%

27 Table 4-24 includes all categories of charges as defined in Table 4-22 and Table 4-23 and includes all PJM Settlements billing adjustments. 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 April 12, 2021.

Table 4-25 compares monthly energy uplift charges by category for the first three months of 2020 and 2021.

Table 4-25 Monthly energy uplift charges: January through March, 2020 and 2021

	2020 Charges (Millions)						2021 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	$0.1	$4.0	$0.0	$0.0	$0.0	$4.1	$0.7	$6.8	$0.7	$0.0	$0.0	$8.2
Feb	$0.2	$1.2	$0.0	$0.0	$0.0	$1.4	$0.9	$13.7	$0.1	$0.0	$0.0	$14.7
Mar	$0.0	$1.6	$0.0	$0.0	$0.0	$1.7	$2.8	$8.6	$0.0	$0.0	$0.1	$11.5
Total (Jan - Mar)	$0.3	$6.8	$0.0	$0.0	$0.0	$7.2	$4.5	$29.1	$0.7	$0.0	$0.1	$34.4
Share (Jan - Mar)	4.3%	94.5%	0.6%	0.0%	0.6%	100.0%	13.1%	84.6%	2.1%	0.0%	0.2%	100.0%

Table 4-26 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges that pay 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.[28] [29] Day-ahead operating reserve charges increased by $4.2 million 1,376 percent in the first three months of 2021 compared to the first three months of 2020.

Table 4-26 Day-ahead operating reserve charges: January through March, 2020 and 2021

Type	(Jan - Mar) 2020 Charges (Millions)	(Jan - Mar) 2021 Charges (Millions)	Change (Millions)	(Jan - Mar) 2020 Share	(Jan - Mar) 2021 Share
Day-Ahead Operating Reserve Charges	$0.3	$4.5	$4.2	99.9%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.1%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$0.3	$4.5	$4.2	100.0%	100.0%

Table 4-27 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 increased by $22.3 million or 328.2 percent in the first three months of 2021 compared to 2020.

Table 4-27 Balancing operating reserve charges: January through March, 2020 and 2021

Type	(Jan - Mar) 2020 Charges (Millions)	(Jan - Mar) 2021 Charges (Millions)	Change (Millions)	(Jan - Mar) 2020 Share	(Jan - Mar) 2021 Share
Balancing Operating Reserve Reliability Charges	$1.2	$12.1	$10.9	17.8%	41.7%
Balancing Operating Reserve Deviation Charges	$3.5	$12.7	$9.2	51.4%	43.8%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$2.1	$4.2	$2.1	30.7%	14.5%
Total	$6.8	$29.1	$22.3	100.0%	100.0%

28 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.
29 See the *2021 Quarterly State of the Market Report for PJM: January through March*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-28 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are equal to the sum of the following three categories: 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 three months of 2021, energy lost opportunity cost deviation charges increased by $3.0 million or 191.0 percent, and make whole deviation charges increased by $6.3 million or 322.5 percent compared to the first three months of 2020.

Table 4-28 Balancing operating reserve deviation charges: January through March, 2020 and 2021

Type	(Jan - Mar) 2020 Charges (Millions)	(Jan - Mar) 2021 Charges (Millions)	Change (Millions)	(Jan - Mar) 2020 Share	(Jan - Mar) 2021 Share
Balancing Operating Reserve Reliability Charges	$1.2	$12.1	$10.9	17.8%	41.7%
Balancing Operating Reserve Deviation Charges	$3.5	$12.7	$9.2	51.4%	43.8%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$2.1	$4.2	$2.1	30.7%	14.5%
Total	$6.8	$29.1	$22.3	100.0%	100.0%

Table 4-29 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $0.7 million or 1,442.5 percent in the first three months of 2021, compared to the first three months of 2020.

Table 4-29 Additional energy uplift charges: January through March, 2020 and 2021

Type	(Jan - Mar) 2020 Charges (Millions)	(Jan - Mar) 2021 Charges (Millions)	Change (Millions)	(Jan - Mar) 2020 Share	(Jan - Mar) 2021 Share
Reactive Services Charges	$0.0	$0.7	$0.7	53.0%	91.1%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.0	$0.1	$0.0	47.0%	8.9%
Total	$0.1	$0.8	$0.7	100.0%	100.0%

Table 4-30 and Table 4-31 show the amount and shares of regional balancing charges in the first three months of 2020 and 2021. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In the first three months of 2021, the largest share of regional charges was paid by real-time load which paid 45.5 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first three months of 2021, regional balancing operating reserve charges increased by $20.2 million compared to the first three months of 2020. Balancing operating reserve reliability charges increased by $10.9 million or 903.4 percent, and balancing operating reserve deviation charges increased by $9.3 million, or 2 percent.

Table 4-30 Regional balancing charges allocation (Millions): January through March, 2020

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$0.9	19.9%	$0.2	5.0%	$0.0	0.0%	$1.2	24.8%
	Real-Time Exports	$0.0	0.8%	$0.0	0.1%	$0.0	0.0%	$0.0	0.9%
	Total	$1.0	20.6%	$0.2	5.1%	$0.0	0.0%	$1.2	25.7%
Deviation Charges	Demand	$2.0	41.5%	$0.2	3.4%	$0.0	0.1%	$2.1	45.0%
	Supply	$0.6	11.9%	$0.1	1.4%	$0.0	0.0%	$0.6	13.3%
	Generator	$0.7	14.6%	$0.1	1.3%	$0.0	0.1%	$0.8	16.0%
	Total	$3.2	68.0%	$0.3	6.1%	$0.0	0.2%	$3.5	74.3%
Total Regional Balancing Charges		$4.2	88.6%	$0.5	11.2%	$0.0	0.2%	$4.7	100%

Table 4-31 Regional balancing charges allocation (Millions): January through March, 2021

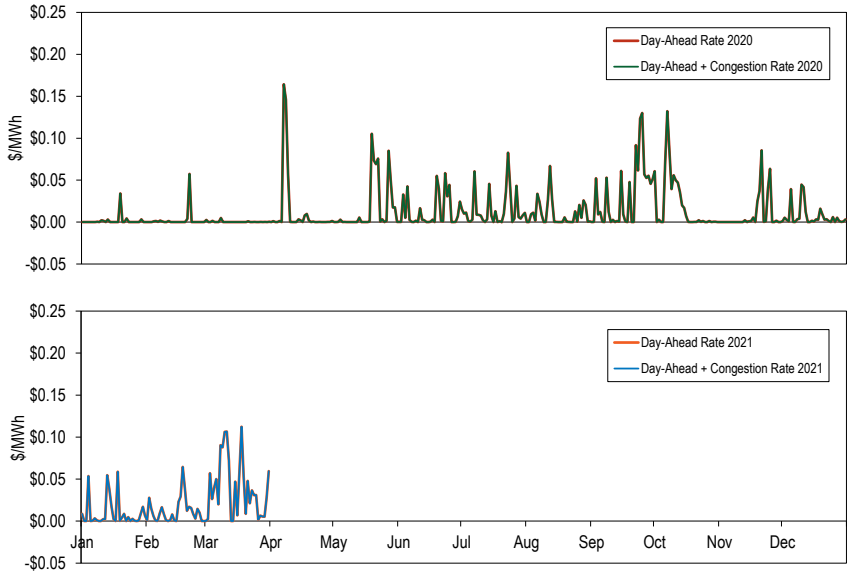
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$9.4	37.7%	$1.6	6.4%	$0.3	1.4%	$11.3	45.5%
	Real-Time Exports	$0.7	2.8%	$0.1	0.4%	$0.0	0.1%	$0.8	3.3%
	Total	$10.1	40.5%	$1.7	6.8%	$0.4	1.5%	$12.1	48.8%
Deviation Charges	Demand	$8.4	33.8%	$0.9	3.8%	$0.2	1.0%	$9.6	38.5%
	Supply	$1.1	4.2%	$0.1	0.5%	$0.0	0.1%	$1.2	4.8%
	Generator	$1.7	6.8%	$0.2	0.9%	$0.0	0.2%	$2.0	7.9%
	Total	$11.2	44.8%	$1.3	5.1%	$0.3	1.2%	$12.8	51.2%
Total Regional Balancing Charges		$21.2	85.3%	$3.0	11.9%	$0.7	2.8%	$24.9	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. Table 4-22 shows how these charges are allocated.[30]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2020 and 2021. The average rate during the first three months of 2021 was $0.020 per MWh, $0.018 per MWh higher than the average during the first three months of 2020. The highest rate during the first three months of 2021 occurred on March 18, when units were called on by reliability engineers due to transmission constraints, and the rate reached $0.112 per MWh, $0.055 per MWh higher than the $0.057 per MWh reached during the first three months of 2020, on February 21. Figure 4-2 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2020 through the first three months of 2021.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): January 2020 through March 2021



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

Figure 4-3 shows the RTO and the regional reliability rates for 2020 and 2021. The average RTO reliability rate in the first three months of 2021 was $0.050 per MWh. The highest RTO reliability rate in the first three months of 2021 occurred on February 15 when the rate reached $0.433 per MWh, $0.392 per MWh higher than the $0.041 per MWh rate reached in 2020, on January 22.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): January 2020 through March 2021

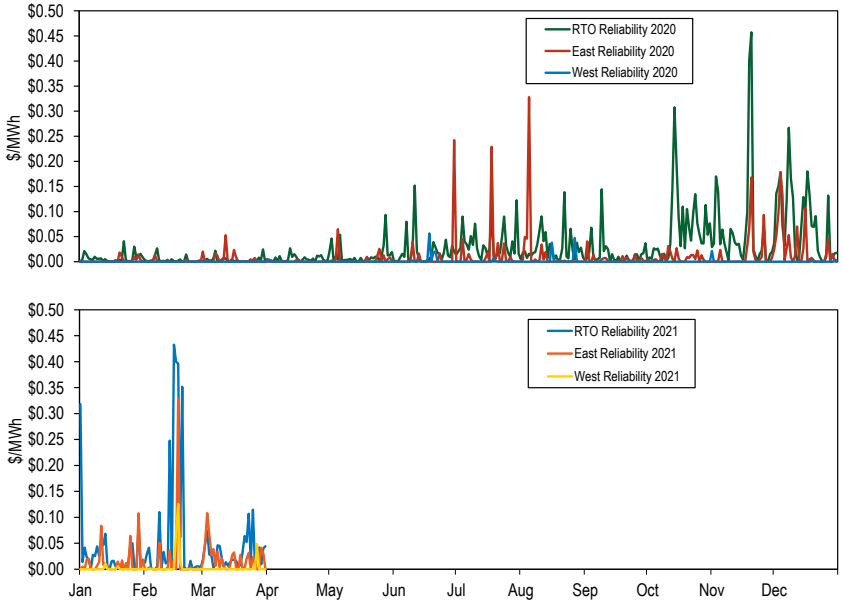


Figure 4-4 shows the RTO and regional deviation rates for 2020 and 2021. The average RTO deviation rate in the first three months of 2021 was $0.116 per MWh. The highest daily rate in the first three months of 2021 occurred on February 15, when the RTO deviation rate reached $1.214 per MWh, $0.735 per MWh more than the $0.479 per MWh rate reached in the first three months of 2020, on January 3.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): January 2020 through March 2021

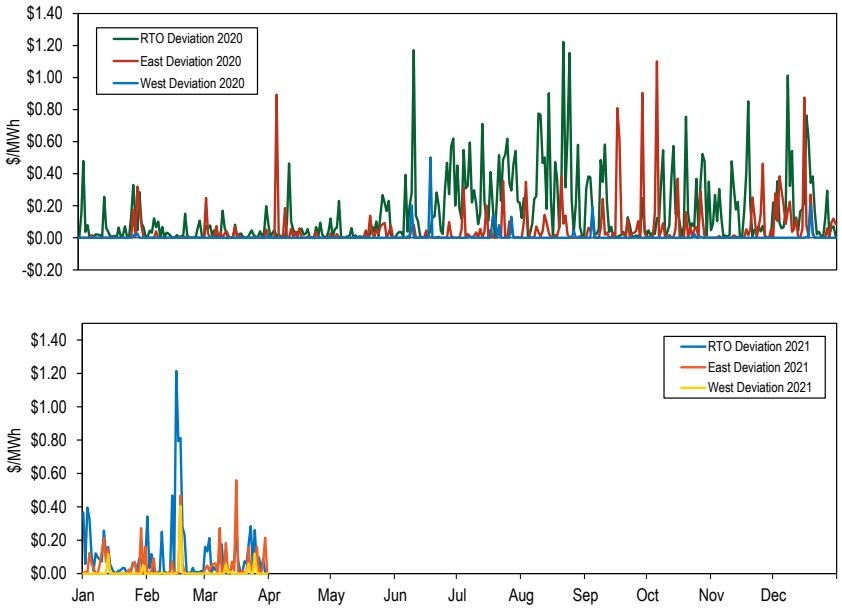


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2020 and 2021. The average lost opportunity cost rate in 2020 was $0.079 per MWh. The highest lost opportunity cost rate in the first three months of 2021 occurred on March 6, when it reached $1.148 per MWh, $0.846 per MWh higher than the $0.302 per MWh rate reached in the first three months of 2020, on March 4.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2020 through March 2021

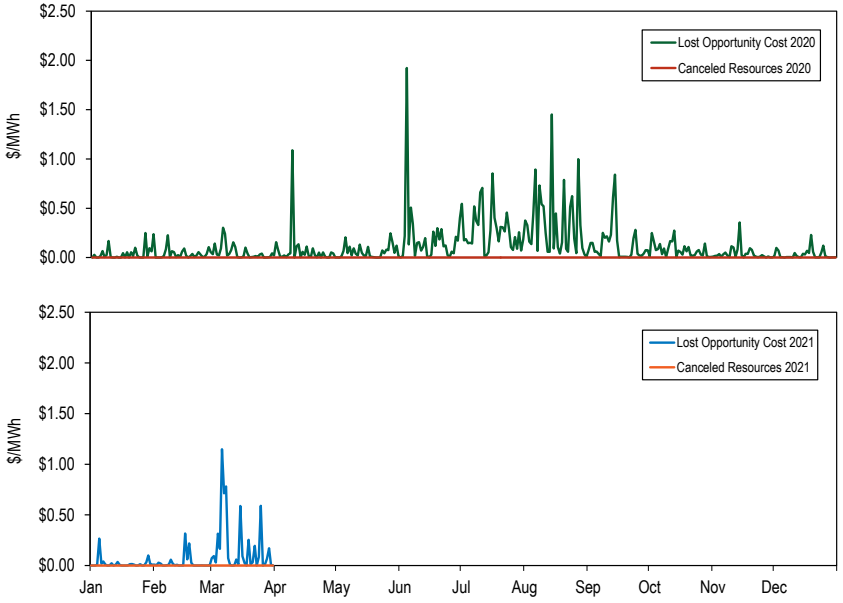


Table 4-32 shows the average rates for each region in each category for 2020 and 2021.

Table 4-32 Operating reserve rates ($/MWh): January through March, 2020 and 2021

Rate	(Jan - Mar) 2020 ($/MWh)	(Jan - Mar) 2021 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.002	0.020	0.018	1,200.1%
Day-Ahead with Unallocated Congestion	0.002	0.020	0.018	1,200.1%
RTO Reliability	0.005	0.050	0.045	895.1%
East Reliability	0.003	0.018	0.015	557.6%
West Reliability	0.000	0.004	0.004	N/A
RTO Deviation	0.047	0.116	0.069	147.3%
East Deviation	0.017	0.050	0.034	204.1%
West Deviation	0.001	0.010	0.009	1,519.3%
Lost Opportunity Cost	0.044	0.079	0.035	79.0%
Canceled Resources	0.000	0.000	NA	N/A

Table 4-33 shows the operating reserve cost of a one MW transaction in the first three months of 2021. For example, in the Eastern Region a day-ahead withdrawal, such as a decrement bid or UTC, (if not offset by other transactions) paid an average rate of $0.265 per MWh with a maximum rate of $1.371 per MWh, a minimum rate of less than $0.001 per MWh and a standard deviation of $0.317 per MWh. The rates in Table 4-33 include all operating reserve charges including RTO deviation charges. The rates also include charges for UTCs, which were implemented on November 1, 2020 and which are treated similarly to DECs. Table 4-33 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels. INCs, DECs, and UTCs have higher rates compared to real-time load because they always result in a deviation while day-ahead and real-time load do not always result in a deviation.

Table 4-33 Operating reserve rates statistics ($/MWh): January through March, 2021

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	1.342	0.245	0.000	0.310
	DEC/UTC	1.371	0.265	0.001	0.317
	DA Load	0.112	0.020	(0.000)	0.027
	RT Load	0.726	0.067	0.000	0.111
	Deviation	1.342	0.245	0.000	0.310
West	INC	1.280	0.205	0.000	0.289
	DEC/UTC	1.309	0.225	0.001	0.295
	DA Load	0.112	0.020	(0.000)	0.027
	RT Load	0.522	0.053	0.000	0.098
	Deviation	1.280	0.205	0.000	0.289

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. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[31] 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 4-34 shows the reactive services rates associated with local voltage support in the first three months of 2020 and 2021. Table 4-34 shows that in 2020 only five zones incurred reactive charges, in addition to reactive capability charges. Real-time load in the PPL Zone, where reactive service charges were the highest, paid an average of $0.064 per MWh for reactive services.

Table 4-34 Local voltage support rates: January through March, 2020 and 2021

Control Zone	(Jan - Mar) 2020 ($/MWh)	(Jan - Mar) 2021 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	0.000	0.0%
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.000	0.000	0.0%
ComEd	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.000	0.000	0.0%
DPL	0.002	0.000	(0.002)	(100.0%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.006	0.000	(0.006)	(100.0%)
Met-Ed	0.000	0.000	0.000	0.0%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.000	0.000	0.000	0.0%
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.064	0.064	NA
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

31 See *2019 State of the Market Report for PJM*, Volume 11, Section 10: Ancillary Service Markets.

Balancing Operating Reserve Determinants

Table 4-35 shows the determinants used to allocate the regional balancing operating reserve charges in the first three months of 2020 and 2021. Total real-time load and real-time exports were 203,017 GWh, 3.4 percent higher in the first three months of 2021 compared to the first three months 2020. Total deviations summed across the demand, supply, and generator categories were 57,156 GWh, 60.7 percent higher in the first three months of 2021 compared to the first three months of 2020.

Table 4-35 Balancing operating reserve determinants (GWh): January through March, 2020 and 2021

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
(Jan - Mar) 2020	RTO	188,726	7,700	196,426	21,840	6,039	7,682	35,561
	East	88,375	2,712	91,088	10,303	3,607	3,556	17,466
	West	100,351	4,988	105,338	11,480	2,331	4,127	17,937
(Jan - Mar) 2021	RTO	194,067	8,950	203,017	42,508	5,737	8,911	57,156
	East	92,666	3,925	96,591	18,560	2,505	4,335	25,400
	West	101,400	5,025	106,426	23,530	3,127	4,577	31,234
Difference	RTO	5,341	1,250	6,591	20,667	(302)	1,229	21,595
	East	4,291	1,213	5,504	8,257	(1,102)	779	7,934
	West	1,050	37	1,087	12,050	796	450	13,296

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of three location types: zones, hubs/aggregates, and interfaces. The deviations, calculated between day-ahead and real-time generation, are aggregated regionally by location type, depending on where the charge occurs.

Credits paid to generators that are defined as operating for reliability purposes are charged to real-time load and exports. Credits paid to generators and credits paid to import transactions that are defined to be operating control deviations on the system, such as energy lost opportunity credits and cancellation credits, are charged to deviations.

Deviations fall into three categories: demand, supply and generator deviations. Table 4-36 shows the different categories by type of transactions that incurred deviations. In the first three months of 2021, 54.1 percent of all RTO deviations were incurred by virtual transactions, or by a transaction that combines virtuals with exports or load. During the first three months of 2021, the volume of UTC deviations represented 33.1 percent of total deviations.

Table 4-36 Deviations by transaction type: January through March, 2021

Deviation Category	Transaction	Deviation (GWh)			Share		
		RTO	East	West	RTO	East	West
Demand	DECs Only	6,699	3,685	2,923	11.7%	14.5%	9.4%
	UTCs Only	18,743	6,161	12,255	32.8%	24.3%	39.2%
	Load Only	14,599	7,800	6,799	25.5%	30.7%	21.8%
	Exports Only	1,716	651	1,066	3.0%	2.6%	3.4%
	Combination of Load/Exports with DECs/UTCs	748	261	487	1.3%	1.0%	1.6%
	Combination of Load/Exports without DECs/UTCs	2	2	0	0.0%	0.0%	0.0%
Supply	INCs Only	4,612	1,812	2,695	8.1%	7.1%	8.6%
	Combination of Imports & INCs	109	84	26	0.2%	0.3%	0.1%
	Imports Only	1,015	610	406	1.8%	2.4%	1.3%
Generators		8,911	4,335	4,577	15.6%	17.1%	14.7%
Total		57,156	25,400	31,234	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-37 shows the geography of charges and credits in the first three months of 2021. Table 4-37 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the PPL Control Zone paid 5.2 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 2.2 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 8.1 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 4.4 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 9.4 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 13.4 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-37 also shows that 87.6 percent of all charges were allocated in control zones, 3.2 percent in hubs and aggregates and 9.2 percent in interfaces.

Table 4-37 Geography of regional charges and credits: January through March, 2021

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$0.4	$0.2	($0.1)	1.2%	0.8%	1.2%	0.0%
	AEP	$4.4	$3.0	($1.3)	14.9%	10.3%	12.3%	0.0%
	APS	$1.3	$0.7	($0.6)	4.4%	2.4%	5.3%	0.0%
	ATSI	$1.6	$1.1	($0.5)	5.5%	3.8%	4.6%	0.0%
	BGE	$1.3	$2.8	$1.5	4.4%	9.4%	0.0%	13.4%
	COMED	$2.8	$2.7	($0.2)	9.6%	9.0%	1.6%	0.0%
	DAY	$0.5	$0.8	$0.3	1.7%	2.9%	0.0%	3.1%
	DUKE	$0.9	$0.5	($0.4)	2.9%	1.7%	3.3%	0.0%
	DUQ	$0.4	$0.0	($0.3)	1.2%	0.1%	3.0%	0.0%
	DOM	$3.3	$6.6	$3.2	11.3%	22.4%	0.0%	29.7%
	DPL	$0.7	$4.9	$4.2	2.4%	16.6%	0.0%	38.2%
	EKPC	$0.7	$1.8	$1.0	2.5%	6.0%	0.0%	9.5%
	External	$0.0	$0.6	$0.6	0.0%	2.0%	0.0%	5.4%
	JCPLC	$0.6	$0.3	($0.4)	2.1%	0.9%	3.4%	0.0%
	MEC	$0.6	$0.2	($0.3)	1.9%	0.8%	3.0%	0.0%
	OVEC	$0.1	$0.0	($0.1)	0.3%	0.0%	0.7%	0.0%
	PECO	$1.2	$0.2	($0.9)	4.0%	0.8%	8.7%	0.0%
	PE	$0.7	$0.5	($0.3)	2.4%	1.5%	2.4%	0.0%
	PEPCO	$0.9	$1.0	$0.1	3.2%	3.4%	0.0%	0.7%
	PPL	$1.5	$0.6	($0.9)	5.2%	2.2%	8.1%	0.0%
	PSEG	$1.7	$0.9	($0.8)	5.7%	3.1%	7.0%	0.0%
	REC	$0.2	$0.0	($0.2)	0.8%	0.0%	2.1%	0.0%
	All Zones	$25.8	$29.4	$3.6	87.6%	100.0%	66.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.3	$0.0	($0.3)	0.9%	0.0%	2.5%	0.0%
	Dominion	$0.1	$0.0	($0.1)	0.4%	0.0%	1.0%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.3%	0.0%	0.8%	0.0%
	New Jersey	$0.1	$0.0	($0.1)	0.2%	0.0%	0.6%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.4%	0.0%	1.2%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$0.3	$0.0	($0.3)	0.9%	0.0%	2.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$0.9	$0.0	($0.9)	3.2%	0.0%	8.5%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.2	$0.0	($0.2)	0.6%	0.0%	1.7%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.3%	0.0%	0.8%	0.0%
	Linden	$0.1	$0.0	($0.1)	0.3%	0.0%	0.8%	0.0%
	MISO	$1.3	$0.0	($1.3)	4.5%	0.0%	12.1%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.1	$0.0	($0.1)	0.2%	0.0%	0.7%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$0.3	$0.0	($0.3)	1.1%	0.0%	2.9%	0.0%
	South Exp	$0.5	$0.0	($0.5)	1.6%	0.0%	4.2%	0.0%
	South Imp	$0.2	$0.0	($0.2)	0.6%	0.0%	1.6%	0.0%
	All Interfaces	$2.7	$0.0	($2.7)	9.2%	0.0%	24.9%	0.0%
	Total	$29.4	$29.4	$0.0	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[32] 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 4-38 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first three months of 2020, balancing operating reserve credits would have been $0.7 million or 22.3 percent lower if they were calculated on a daily basis. In the first three months of 2021, balancing operating reserve credits would have been $2.8 million or 13.5 percent lower if they were calculated on a daily basis.

Table 4-38 Intraday segments and daily balancing operating reserve credits: January through March, 2020 and 2021

	2020 BOR Credits (Millions)			2021 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$1.6	$1.3	($0.3)	$4.8	$4.2	($0.5)
Feb	$0.7	$0.5	($0.2)	$10.6	$9.4	($1.2)
Mar	$0.9	$0.7	($0.2)	$5.0	$4.0	($1.0)
Apr	$1.1	$0.9	($0.2)			
May	$1.9	$1.6	($0.3)			
Jun	$5.1	$4.1	($1.0)			
Jul	$8.8	$5.7	($3.0)			
Aug	$8.1	$6.0	($2.1)			
Sep	$3.7	$2.8	($0.9)			
Oct	$6.8	$5.9	($0.9)			
Nov	$7.8	$7.0	($0.8)			
Dec	$11.8	$11.0	($0.9)			
Total (Jan - Mar)	$3.2	$2.5	($0.7)	$20.4	$17.6	($2.8)

32 See PJM "Manual 28: Operating Reserve Accounting," Rev. 83 (Dec. 3, 2019).

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 4-39 compares the impact on day-ahead LOC credits of adopting five minute settlements over hourly settlements in April 2018 and the impact of having adopted the recommended daily settlements over five minute settlements. For the first three months of 2021, LOC credits would have been 12.1 percent lower if they had been settled on an hourly basis rather than on a five minute basis. For the first three months of 2021, LOC credits would have been $1.6 million or 34.8 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute settlement.

Table 4-39 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through March, 2021

	2021 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$0.4	$0.3	($0.1)	$0.2	($0.1)
Feb	$0.6	$0.5	($0.1)	$0.4	($0.2)
Mar	$3.5	$3.1	($0.4)	$2.3	($1.2)
Total (Jan - Mar)	$4.5	$3.9	($0.5)	$2.9	($1.6)

Uplift Credits and Offer Capping

Absent 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 market power in the energy market.[33] 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 4-40 shows the uplift credits paid to units that were committed and dispatched on cost offers during the first three months of 2021.

Table 4-40 Operating Reserve Credits by Offer Type: January through March, 2021

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Operating Reserve Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)
Cost	$0.5	$4.1	0.3	$0.4
Price	$4.0	$14.1	0.0	$0.0
Price PLS	$0.0	$1.3	0.0	$0.0
Cost & Price	$0.0	$0.9	0.0	$0.0
Cost & PLS	$0.0	$0.0	0.0	$0.0
Price & PLS	$0.0	$0.0	0.0	$0.0
Total	$4.5	$20.3	0.3	$0.4

Table 4-41 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, 90.8 percent went to units that were committed on price schedules less flexible than PLS.

Table 4-41 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through March, 2021

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during Hot and Cold Weather Alerts
Committed on cost (cost capped)	$0	0.0%
Committed on price schedule as flexible as PLS	$0	0.0%
Committed on price schedule less flexible than PLS	$26,908	90.8%
Committed on price PLS	$2,737	9.2%
Total	$29,645	100.0%

33 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>.