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.

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.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design 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.

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

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

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

Overview

Energy Uplift Credits

- **Types of credits.** In the first nine months of 2020, energy uplift credits were \$58.6 million, including \$7.0 million in day-ahead generator credits, \$31.8 million in balancing generator credits, \$17.1 million in lost opportunity cost credits, and \$2.2 million in local constraint control credits.
- **Types of units.** In the first nine months of 2020, coal units received 89.5 percent of all day-ahead generator credits. During the same time period, combustion turbines received 88.0 percent of all balancing generator credits and 95.8 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In the first nine months of 2020, 86.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first nine months of 2020, less than 0.1 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 76.6 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 18.0 percent of all credits. The top 10 organizations received 73.3 percent of all credits. The HHI for day-ahead operating

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

reserves was 8481, the HHI for balancing operating reserves was 3859 and the HHI for lost opportunity cost was 5325, all of which are classified as highly concentrated.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $4.6 million or 36.6 percent, in the first nine months of 2020 compared to the first nine months of 2019, from $12.5 million to $17.1 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive lost opportunity cost credits as a result. The amount of day-ahead generation paid LOC credits for this reason increased by 637.1 GWh or 131.4 percent during the first nine months of 2020, compared to the first nine months of 2019, from 484.8 GWh to 1,121.9 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges decreased by $11.8 million, or 16.8 percent, in the first nine months of 2020 compared to the first nine months of 2019, from $70.5 million to $58.6 million.
- **Energy Uplift Charges Categories.** The decrease of $11.8 million in the first nine months of 2020 was comprised of a $6.9 million decrease in day-ahead operating reserve charges, a $4.9 million decrease in balancing operating reserve charges, and a $0.1 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.012 per MWh, real-time load paid $0.024 per MWh, a DEC paid $0.345 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.333 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.012 per MWh, real-time load paid $0.017 per MWh, a DEC paid $0.314 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.302 per MWh in the first nine months of 2020.
- **Reactive Services Rates.** JCPL, PPL, and EKPC control zones were the three zones with the highest local voltage support rates, excluding reactive capability payments. JCPL had a rate of $0.010 per MWh, PPL had a rate of $0.006 per MWh, and EKPC had a rate of $0.005.

Geography of Charges and Credits

- In the first nine months of 2020, 88.8 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 3.9 percent by transactions at hubs and aggregates, and 7.3 percent by transactions at interchange interfaces.
- In the first nine months of 2020, generators in the Eastern Region received 35.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, generators in the Western Region received 61.3 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first nine months of 2020, external generators received 2.9 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 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 operating reserves 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 operating reserves, 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 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: Not 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.[5])
- 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.)
- 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

5 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 2, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

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 operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of 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.[6])
- 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 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 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.)
- 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. New recommendation. Status: Not adopted.)

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on March 21, 2019. PJM began posting unit specific uplift reports on May 1, 2019.

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. 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 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). This tradeoff would be created in more extensive form by PJM's full convex hull pricing proposal.

When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market 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.[7] 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.

Up to congestion transactions continued to pay no energy uplift charges in the first nine months of 2020, which means that all others who pay these charges paid too much.[8] On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[9] 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.

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.

7 On March 21, 2019 FERC accepted PJM's Order No. 844 compliance filing. 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.

8 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change.

9 See 172 FERC ¶ 61,046.

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 nine months of 2019 and 2020.[10] In the first nine months of 2020, energy uplift credits decreased by $11.8 million or 16.8 percent compared to the first nine months of 2019.

Table 4-1 Energy uplift credits by category: January through September, 2019 and 2020[11]

Category	Type	2019 Credits (Millions)	2020 Credits (Millions)	Change	Percent Change	2019 Share	2020 Share
Day-Ahead	Generators	$13.9	$7.0	($6.9)	(49.5%)	19.8%	12.0%
	Imports	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	99.6%	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$40.7	$31.8	($8.9)	(21.9%)	57.7%	54.2%
	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	$2.7	$2.2	($0.5)	(18.8%)	3.8%	3.7%
	Lost Opportunity Cost	$12.5	$17.1	$4.6	36.6%	17.8%	29.1%
Reactive Services	Day-Ahead	$0.2	$0.1	($0.1)	(65.6%)	0.3%	0.1%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(87.2%)	0.0%	0.0%
	Reactive Services	$0.3	$0.3	$0.1	35.1%	0.4%	0.6%
	Synchronous Condensing	$0.0	$0.0	($0.0)	(100.0%)	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	$0.2	$0.2	($0.0)	(10.1%)	0.2%	0.3%
Total		$70.5	$58.6	($11.8)	(16.8%)	100.0%	100.0%

10 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on October 9, 2020.
11 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 the first nine months of 2019 and 2020. Uplift credits decreased for most unit types. A combination of factors led to decreased uplift payments in the first nine months of 2020. Milder winter weather in the first three months of 2020, measured by reduced heating degree days and cold weather alerts, contributed to low natural gas prices, reducing the costs of gas units and reducing the need for, and level of, make whole payments, and reducing uplift credits for combustion turbines. Similarly, reduced load beginning in March 2020 resulting from a combination of weather and COVID-19 caused sustained and significant decreases in generation and fuel prices. Coal units had the largest reduction in uplift credits, with a reduction of $7.0 million or 45.7 percent in the first nine months of 2020 compared with the first nine months of 2019. Combustion turbines had the second largest reduction in uplift credits with a reduction of $3.2 million or 6.4 percent. The largest decrease in uplift, 92.8 percent of the total reduction in day ahead operating reserves in the first nine months of 2020, was accounted for by a small number of coal units in the BGE and Pepco Zones.

Wind turbines are less common recipients of uplift, and in the first nine months of 2020 uplift credits to wind units were $0.1 million, down by 25.3 percent compared to the first nine months of 2019.

Table 4-2 Energy uplift credits by unit type: January through September, 2019 and 2020[12 13]

Unit Type	(Jan - Sep) 2019 Credits (Millions)	(Jan - Sep) 2020 Credits (Millions)	Change	Percent Change	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Combined Cycle	$2.7	$2.0	($0.7)	(24.6%)	3.8%	3.5%
Combustion Turbine	$49.5	$46.4	($3.2)	(6.4%)	70.3%	79.0%
Diesel	$0.6	$0.5	($0.1)	(13.2%)	0.8%	0.9%
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	$0.1	$0.0	($0.1)	(98.6%)	0.1%	0.0%
Steam - Coal	$15.4	$8.4	($7.0)	(45.7%)	21.8%	14.3%
Steam - Other	$2.0	$1.2	($0.8)	(38.2%)	2.9%	2.1%
Wind	$0.2	$0.1	($0.0)	(25.3%)	0.2%	0.2%
Total	$70.5	$58.6	($11.8)	(16.8%)	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2020. The characteristics of the different unit types explain why the shares of credit types are dominated by a particular unit type. For example, the majority of day-ahead credits, 95.1 percent, went to steam units. This is because steam units tend to be longer lead time units that need to be 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 88.0 percent of balancing credits and 94.6 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.

12 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.
13 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

Table 4-3 Energy uplift credits by unit type: January through September, 2020

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	2.8%	2.2%	0.0%	16.9%	3.6%	33.8%	0.0%	13.5%
Combustion Turbine	2.0%	88.0%	0.0%	79.4%	94.6%	55.1%	0.0%	86.5%
Diesel	0.1%	0.8%	0.0%	2.5%	1.2%	0.0%	0.0%	0.1%
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	89.5%	6.2%	0.0%	0.0%	0.3%	11.0%	0.0%	0.0%
Steam - Other	5.6%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	0.0%	0.1%	0.0%	1.2%	0.3%	0.0%	0.0%	0.0%
Total (Millions)	$7.0	$31.8	$0.0	$2.2	$17.1	$0.4	$0.0	$0.2

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the day-ahead energy market when needed in real time to address reliability issues of various types that would otherwise not have been committed in the day-ahead market. Such reliability issues include black start service and reactive service or reactive transfer interface control needed to maintain system reliability in a zone.[14] 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.[15] 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 the total day-ahead generation and the subset of that generation committed for reliability by PJM. In the first nine months of 2020, 0.1 percent of the total day-ahead generation was committed for reliability by PJM, 0.2 percentage points lower than in the first nine months of 2019. The decrease in day-ahead generation committed for reliability by PJM was due to a reduction of the need to commit uneconomic units in BGE and Pepco for reliability.

Table 4-4 Day-ahead generation committed for reliability (GWh): January 2019 through September 2020

	2019			2020		
	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	77,616	81	0.1%	71,116	0	0.0%
Feb	66,102	91	0.1%	65,827	5	0.0%
Mar	68,331	305	0.4%	63,058	6	0.0%
Apr	57,926	0	0.0%	55,091	41	0.1%
May	63,432	131	0.2%	58,114	117	0.2%
Jun	67,899	301	0.4%	69,651	60	0.1%
Jul	83,474	327	0.4%	85,585	63	0.1%
Aug	77,632	367	0.5%	79,173	88	0.1%
Sep	69,009	357	0.5%	65,105	145	0.2%
Oct	60,594	112	0.2%			
Nov	63,347	8	0.0%			
Dec	69,808	61	0.1%			
Total (Jan - Sep)	631,423	1,960	0.3%	612,721	525	0.1%
Total	825,172	2,142	0.3%	612,721	525	0.1%

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 operating reserve credits. Total day-ahead operating reserve credits in 2020 were $7.0 million. The top 10 units received $6.1

14 See OA Schedule 1 § 3.2.3(b).
15 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>.

million or 87.1 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 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 nine months of 2020, 76.6 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, of which 72.1 percent was paid as day-ahead operating reserve credits. The remaining 23.4 percent of the day-ahead generation committed for reliability by PJM was economic, meaning prices covered all resource operating costs.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): January through September, 2020

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	0.0	0.0	0.0
Feb	0.0	4.6	0.0	4.6
Mar	6.0	0.1	0.0	6.1
Apr	0.0	33.7	7.3	41.0
May	14.9	82.0	20.6	117.4
Jun	0.5	59.4	0.0	59.8
Jul	0.0	33.3	29.4	62.7
Aug	2.5	24.2	61.3	88.0
Sep	0.0	141.1	4.1	145.2
Total (Jan - Sep)	23.8	378.3	122.8	524.9
Share	4.5%	72.1%	23.4%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2020 were $7.0 million, of which $4.6 million or 65.6 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. An additional 0.9 percent, or $0.1 million, was paid to units scheduled to provide black start or reactive services.[16]

16 The value for black start and reactive in the 2020 Quarterly State of the Market Report for PJM: January through June was incorrect.

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 $27.9 million or 88.0 percent of all balancing operating reserve (BOR) credits in the first nine months of 2020. The majority of these credits, 97.1 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[17] Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Uplift is higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions, unless the PJM dispatcher changes the dispatch reason to self scheduled. PJM dispatchers should not decide which units qualify for uplift. 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. 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 decreased by 21.9 percent from the first nine months of 2019 to the first nine months of 2020. The decrease was a result of lower natural gas prices in the first nine months of 2020 compared to the first nine months of 2019. The decrease in credits in the Dominion, AEP, and ComEd Zones accounted for 70.9 percent of the total change in balancing operating reserve credits. While overall generation in the Dominion, AEP, and ComEd Zones increased by only 2.0 percent in the first

17 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.

nine months of 2020 compared to the first nine months of 2019, generation by combustion turbines in the three regions increased by 21.7 percent.

The credits paid to combustion turbines committed in real time without a day-ahead commitment occurs despite the fact that total combustion turbines are committed in the day-ahead energy market at levels comparable 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 nine months of 2020, generation by combustion turbines was 3.5 percent lower in the real-time energy market than in the day-ahead energy market. However, this varied month to month, with some months having greater day-ahead generation compared to real-time generation. Table 4-6 shows that only 10.6 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 24.3 percent of generation from combustion turbines in the real-time market was uneconomic and required $27.9 million in BOR credits.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: January through September, 2020

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	607	0.9%	$0.0	549	15.1%	$1.5	(10.4%)
Feb	399	0.2%	$0.0	316	11.0%	$0.6	(26.2%)
Mar	434	0.2%	$0.0	457	11.9%	$0.8	5.1%
Apr	379	0.6%	$0.0	394	25.0%	$0.8	3.9%
May	822	0.9%	$0.0	825	24.2%	$1.7	0.3%
Jun	1,908	1.4%	$0.0	1,699	25.6%	$4.5	(12.3%)
Jul	4,320	3.0%	$0.1	4,216	23.1%	$7.9	(2.5%)
Aug	2,410	2.2%	$0.0	2,477	29.6%	$7.4	2.7%
Sep	1,444	1.1%	$0.0	1,359	27.5%	$2.8	(6.2%)
Total (Jan - Sep)	12,722	10.6%	$0.1	12,294	24.3%	$27.9	(3.5%)

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, which constitute 85.4 percent of total BOR credits.

Table 4-7 shows real-time generation by combustion turbines by day-ahead commitment status in the first nine months of 2020. CTs that operated on a day-ahead schedule constituted 73.1 percent of real-time generation by CTs, of which 19.7 percent was uneconomic in the real-time market and received $0.8 million in BOR credits.

In the first nine months of 2020, 26.9 percent of real-time generation by CTs was from CTs that operated outside of a day-ahead schedule, of which 36.8 percent was uneconomic in the real-time market and received $27.1 million in BOR credits.

Thus, while enough total generation from CTs may be committed economically in the day-ahead energy market, uplift can still be incurred because the committed units operate at different times than originally scheduled and when CTs operate in real time outside of a day-ahead schedule. For example, in January 2020, although total CT generation committed in the day-ahead market was greater than CT generation in real time, 33.9 percent of real-time generation by CTs operated outside of a day-ahead schedule.

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 September, 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
Apr	257	65.2%	16.9%	$0.0	137	34.8%	40.3%	$0.8
May	579	70.2%	15.2%	$0.1	246	29.8%	45.2%	$1.7
Jun	1,210	71.2%	22.8%	$0.1	489	28.8%	32.6%	$4.4
Jul	3,255	77.2%	19.2%	$0.2	962	22.8%	36.4%	$7.7
Aug	1,750	70.6%	26.1%	$0.3	727	29.4%	38.0%	$7.1
Sep	1,015	74.6%	24.0%	$0.1	345	25.4%	38.0%	$2.7
Total (Jan - Sep)	8,985	73.1%	19.7%	$0.8	3,309	26.9%	36.8%	$27.1

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. This LOC will be 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 4-8 shows monthly day-ahead and real-time LOC credits in the first nine months of 2019 and 2020. In the first nine months of 2020, LOC credits increased by $4.6 million or 36.6 percent compared to the first nine months of 2019. The increase of $4.6 million is comprised of a $4.2 million increase in day-ahead LOC and a $0.4 million increase 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 nine months of 2020, wind units received $0.5 million of real-time LOC, down by 71.2 percent compared to the first nine months of 2019. In the first nine months of 2020, real-time LOC credits to wind units accounted for 42.9 percent of the uplift payments to wind units. Wind units in the AEP and ComEd Zones received 99.1 percent of those real-time lost opportunity cost credits.

Table 4-9 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 nine months of 2020, 15.7 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.1 percentage points higher than in the first nine months of 2019. Generation by natural gas fired combustion turbines increased by 24.6 percent during the first nine months of 2020 compared to the first nine months of 2019, and coal generation decreased by 24.9 percent during the first nine of months of 2020 compared to the first nine months of 2019. During the first nine months of 2020 compared to 2019, day-ahead generation by combustion turbines increased 51.1 percent, day-ahead generation not requested in real time increased disproportionately by 104.4 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased disproportionately by 131.4 percent. Unlike coal units, combustion turbines that clear the day-ahead energy market still have to be instructed by PJM in real time to come online. The combination of increased combustion turbines scheduled in the day-ahead energy market and this different treatment was a key factor in increasing LOC credits to generation from.

Table 4-8 Monthly lost opportunity cost credits (Millions): January 2019 through September 2020

	2019			2020		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.4	$0.0	$0.5	$0.5	$0.0	$0.5
Feb	$0.1	$0.0	$0.2	$0.4	$0.0	$0.4
Mar	$0.4	$0.0	$0.5	$0.6	$0.1	$0.6
Apr	$0.5	$0.0	$0.5	$0.3	$0.5	$0.9
May	$1.6	$0.1	$1.6	$0.8	$0.0	$0.8
Jun	$0.6	$0.0	$0.7	$3.3	$0.1	$3.4
Jul	$1.9	$0.0	$2.0	$4.2	$0.1	$4.2
Aug	$1.7	$0.0	$1.7	$4.5	$0.1	$4.5
Sep	$4.7	$0.2	$4.9	$1.6	$0.0	$1.7
Oct	$2.2	$0.1	$2.3			
Nov	$1.4	$0.1	$1.6			
Dec	$0.8	$0.0	$0.8			
Total (Jan - Sep)	$12.0	$0.5	$12.5	$16.2	$0.9	$17.1
Share (Jan - Sep)	96.0%	4.0%	100.0%	94.6%	5.4%	100.0%
Total	$16.4	$0.8	$17.1	$16.2	$0.9	$17.1
Share	95.5%	4.5%	100.0%	94.6%	5.4%	100.0%

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): January 2019 through September 2020

	2019			2020		
	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	692	38	13	873	171	73
Feb	370	19	4	653	114	49
Mar	524	48	12	729	103	55
Apr	619	71	21	656	95	37
May	848	171	49	1,126	188	80
Jun	938	128	46	2,278	438	244
Jul	2,555	197	68	4,759	590	272
Aug	1,901	197	109	2,728	386	181
Sep	1,808	320	163	1,696	346	131
Oct	2,125	289	155			
Nov	1,212	183	61			
Dec	777	128	59			
Total (Jan - Sep)	10,255	1,189	485	15,498	2,431	1,122
Share (Jan - Sep)	100.0%	11.6%	4.7%	100.0%	15.7%	7.2%
Total	14,369	1,789	760	15,498	2,431	1,122

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 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[18] 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. [19]

Table 4-10 Dispatch status, commitment status and uplift eligibility[20]

			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 4-11 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-11 shows that in the first nine months of 2020, 42.7 percent of generation in the day-ahead energy market was pool scheduled and 45.0 percent of generation in the real-time energy market was pool scheduled. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. Most nuclear and coal resources, which make up 52.7 percent of real-time generation, are self scheduled.

Table 4-11 Day-ahead and real-time generation by status and eligibility to set LMP (GWh): January through September, 2020

	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	59,999	137,625	153,234	114,770	130,743	16,351	612,721	261,864	350,857	174,768
Share of Day-Ahead	9.8%	22.5%	25.0%	18.7%	21.3%	2.7%	100.0%	42.7%	57.3%	28.5%
Real-Time Generation	52,586	131,055	153,117	114,035	141,601	19,587	611,980	275,222	336,757	166,620
Share of Real-Time	8.6%	21.4%	25.0%	18.6%	23.1%	3.2%	100.0%	45.0%	55.0%	27.2%

18 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
19 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.
20 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

Economic and Noneconomic Generation[21]

Economic generation includes units scheduled day ahead 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 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 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In the first nine months of 2020, 86.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 67.2 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 4-12 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September, 2020

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	227,517	34,347	261,864	86.9%	13.1%
Real-Time	156,818	76,659	233,477	67.2%	32.8%

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the day or segment. Table 4-13 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2020, 0.6 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.2 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): January through September, 2020

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	261,864	1,631	0.6%
Real-Time	233,477	2,729	1.2%

Concentration of Energy Uplift Credits

There is a high level of concentration in the units and companies receiving energy uplift credits. 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 transparency has made it almost impossible for competition to affect these payments.[22]

Figure 4-1 shows the concentration of energy uplift credits. The top 10 units received 18.0 percent of total energy uplift credits in the first nine months of 2020, compared to 23.7 percent in the first nine months of 2019. In the first nine months of 2020, 239 units received 90 percent of all energy uplift credits, compared to 245 units in the first nine months of 2019.

21 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.

22 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.

Figure 4-1 Cumulative share of energy uplift credits: January through September, 2019 and 2020 by unit

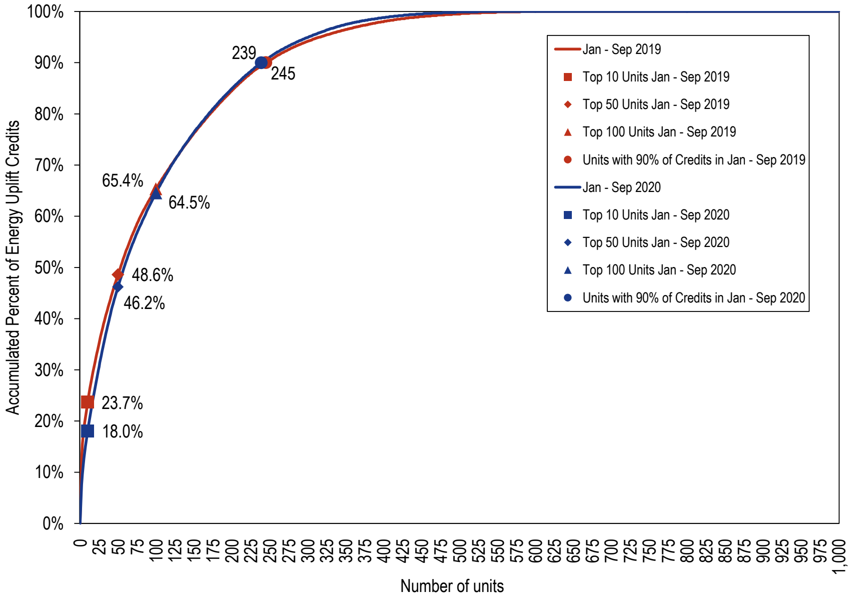


Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first nine months of 2020.

Table 4-14 Top 10 units and organizations energy uplift credits: January through September, 2020

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$6.1	87.1%	$6.9	97.7%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$4.3	13.7%	$23.8	74.9%
	Local Constraints Control	$1.5	69.3%	$2.2	99.7%
	Lost Opportunity Cost	$4.2	24.7%	$13.8	81.0%
Reactive Services		$0.4	94.8%	$0.4	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	43.7%	$0.1	90.9%
Total		$10.6	18.0%	$43.0	73.3%

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2020, 91.8 percent of all credits paid to these units were allocated to deviations while the remaining 8.2 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: January through September, 2020

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$0.3	$0.0	$0.0	$3.4	$0.6	$0.0	$4.3
Share	8.0%	0.1%	0.0%	77.2%	14.7%	0.0%	100.0%

In the first nine months of 2020, concentration in all energy uplift credit categories was high.[23] [24] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-16 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8481, for balancing operating reserve credits to generators was 3859, for lost opportunity cost credits was 5325 and for reactive services credits was 9562. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: January through September, 2020

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8481	3265	10000	100.0%	54.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	70.9%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3859	778	10000	100.0%	27.3%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
	Lost Opportunity Cost	5325	1168	10000	100.0%	19.9%
Reactive Services		9562	5236	10000	100.0%	35.0%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9563	5045	10000	100.0%	19.3%
Total		3370	617	9864	99.3%	21.6%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-17 through Table 4-20 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 18.0 percent of all credits, with the top recipient receiving 3.9 percent. The top 10 units receiving day-ahead operating reserves received 87.1 percent. The top 10 recipients of balancing operating reserves received 13.7 percent of balancing operating reserve credits. The top 10 recipients of lost opportunity cost credits received 24.7 percent of total lost opportunity cost credits.

Table 4-17 Top 10 recipients of total uplift: January through September, 2020

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 1 F	BGE	$2,286,801	3.9%
2	BC BRANDON SHORES 2 F	BGE	$2,165,940	3.7%
3	BC PERRYMAN 6 CT	BGE	$1,199,938	2.0%
4	PEP MORGANTOWN 2 F	Pepco	$926,841	1.6%
5	DPL INDIAN RIVER 4 F	DPL	$868,608	1.5%
6	COM 900 ELWOOD 7 CT	ComEd	$705,029	1.2%
7	COM 900 ELWOOD 5 CT	ComEd	$694,385	1.2%
8	COM 900 ELWOOD 1 CT	ComEd	$599,082	1.0%
9	PEP MORGANTOWN 1 F	Pepco	$562,365	1.0%
10	COM 900 ELWOOD 2 CT	ComEd	$561,257	1.0%
Total of Top 10			$10,570,246	18.0%
Total Uplift Credits			$58,648,284	100.0%

Table 4-18 Top 10 recipients of day-ahead generation credits: January through September, 2020

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 1 F	BGE	$2,070,730	29.4%
2	BC BRANDON SHORES 2 F	BGE	$1,525,928	21.7%
3	DPL INDIAN RIVER 4 F	DPL	$739,881	10.5%
4	PEP MORGANTOWN 2 F	Pepco	$671,158	9.5%
5	PEP MORGANTOWN 1 F	Pepco	$516,264	7.3%
6	PEP CHALKPOINT 2 F	Pepco	$145,113	2.1%
7	COM 3 POWERTON 5	ComEd	$136,128	1.9%
8	PL BRUNNER ISLAND 3 F	PPL	$128,535	1.8%
9	PEP CHALKPOINT 4 F	Pepco	$117,987	1.7%
10	PEP CHALKPOINT 3 F	Pepco	$79,282	1.1%
Total of Top 10			$6,131,006	87.1%
Total day-ahead operating reserve credits			$7,038,678	100.0%

Table 4-19 Top 10 recipients of balancing operating reserve credits: January through September, 2020

Rank	Unit Name	Zone	Balancing Operating Reserve Credit	Share of Balancing Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$640,012	2.0%
2	AEP FOOT HILLS 2 CT	AEP	$434,970	1.4%
3	COM 951 AURORA 4 CT	ComEd	$434,792	1.4%
4	VP MARSHRUN 1 CT	Dominion	$431,958	1.4%
5	AEP RIVERSIDE ZELDA 3 CT	AEP	$421,936	1.3%
6	AEP RIVERSIDE ZELDA 2 CT	AEP	$417,630	1.3%
7	COM 951 AURORA 2 CT	ComEd	$407,234	1.3%
8	VP MARSHRUN 3 CT	Dominion	$402,652	1.3%
9	COM 951 AURORA 3 CT	ComEd	$378,335	1.2%
10	COM 952 ROCKFORD 12 CT	ComEd	$375,464	1.2%
Total of Top 10			$4,344,983	13.7%
Total balancing operating reserve credits			$31,770,587	100.0%

Table 4-20 Top 10 recipients of lost opportunity cost credits: January through September, 2020

Rank	Unit Name	Zone	Lost Opportunity Cost Credit	Share of Lost Opportunity Cost Credits
1	BC PERRYMAN 6 CT	BGE	$817,676	4.8%
2	COM 900 ELWOOD 5 CT	ComEd	$522,510	3.1%
3	COM 900 ELWOOD 7 CT	ComEd	$507,000	3.0%
4	COM 900 ELWOOD 2 CT	ComEd	$449,979	2.6%
5	COM 900 ELWOOD 1 CT	ComEd	$411,750	2.4%
6	COM 900 ELWOOD 6 CT	ComEd	$352,221	2.1%
7	COM 900 ELWOOD 4 CT	ComEd	$346,925	2.0%
8	FE LEMOYNE 1 CT	ATSI	$279,239	1.6%
9	FE RICHLAND 5 CT	ATSI	$272,452	1.6%
10	COM 900 ELWOOD 3 CT	ComEd	$267,099	1.6%
Total of Top 10			$4,226,850	24.7%
Total lost opportunity cost credits			$17,090,303	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 4-21 and Table 4-22 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-21 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	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	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	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 4-22 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 Charge	Zonal Real-Time Load
	Reactive Services Generator			
	Reactive Services LOC			
	Reactive Services Condensing		Reactive Services Local Constraint	Applicable Requesting Party
	Reactive Services Synchronous Condensing LOC			
		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	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve			
	Black Start Testing			

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. By the end of the first nine months of 2020, the cumulative resettlement requests totaled $2.2 million. Of that amount, PJM has agreed and resettled 59.5 percent of the requests, 30.4 percent remains pending. The remaining 10.2 percent occurred prior to September 2018 and require a directive for FERC for them to be resettled. The MMU continues to bring new cases to the attention of PJM.

Energy Uplift Charges Results

Energy Uplift Charges

Total energy uplift charges decreased by $11.8 million or 16.8 percent in the first nine months of 2020 compared to the first nine months of 2019. Energy uplift charges in the first nine months of 2020 were $58.6 million.

Table 4-23 shows total energy uplift charges by category in the first nine months of 2019 and 2020.[25] The decrease of $11.8 million is comprised of a decrease of $6.9 million in day-ahead operating reserve charges, a decrease of $4.9 million in balancing operating reserve charges and a decrease of $0.1 million in reactive service charges.

Table 4-23 Total energy uplift charges by category: January through September, 2019 and 2020

Category	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$14.0	$7.0	($6.9)	(49.6%)
Balancing Operating Reserves	$55.9	$51.0	($4.9)	(8.7%)
Reactive Services	$0.5	$0.4	($0.1)	(11.5%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.2	$0.2	($0.0)	(8.9%)
Total	$70.5	$58.6	($11.8)	(16.8%)
Energy Uplift as a Percent of Total PJM Billing	0.2%	0.2%	(0.0%)	(0.2%)

Table 4-24 compares monthly energy uplift charges by category for the first nine months of 2019 and 2020.

Table 4-24 Monthly energy uplift charges: January 2019 through September 2020

	2019 Charges (Millions)						2020 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	$1.0	$6.5	$0.1	$0.0	$0.0	$7.6	$0.1	$4.0	$0.0	$0.0	$0.0	$4.1
Feb	$0.8	$3.9	$0.0	$0.0	$0.0	$4.7	$0.2	$1.2	$0.0	$0.0	$0.0	$1.4
Mar	$2.3	$4.6	$0.0	$0.0	$0.0	$6.9	$0.0	$1.6	$0.0	$0.0	$0.0	$1.7
Apr	$0.1	$4.0	$0.0	$0.0	$0.0	$4.2	$0.8	$2.0	$0.1	$0.0	$0.1	$2.9
May	$1.4	$4.1	$0.1	$0.0	$0.1	$5.7	$1.0	$2.7	$0.3	$0.0	$0.0	$4.0
Jun	$2.6	$4.8	$0.2	$0.0	$0.0	$7.5	$0.9	$8.5	$0.0	$0.0	$0.0	$9.5
Jul	$1.4	$10.6	$0.0	$0.0	$0.0	$12.0	$1.2	$13.0	$0.0	$0.0	$0.0	$14.2
Aug	$2.7	$6.8	$0.0	$0.0	$0.0	$9.5	$0.8	$12.7	$0.0	$0.0	$0.0	$13.5
Sep	$1.7	$10.6	$0.0	$0.0	$0.0	$12.3	$2.1	$5.3	$0.0	$0.0	$0.0	$7.4
Oct	$0.9	$8.3	$0.0	$0.0	$0.0	$9.2						
Nov	$0.2	$5.6	$0.0	$0.0	$0.0	$5.8						
Dec	$0.5	$2.5	$0.1	$0.0	$0.0	$3.1						
Total (Jan - Sep)	$14.0	$55.9	$0.5	$0.0	$0.2	$70.5	$7.0	$51.0	$0.4	$0.0	$0.2	$58.6
Share (Jan - Sep)	19.8%	79.3%	0.7%	0.0%	0.2%	100.0%	12.0%	87.0%	0.7%	0.0%	0.3%	100.0%
Total	$15.5	$72.2	$0.6	$0.0	$0.2	$88.5	$7.0	$51.0	$0.4	$0.0	$0.2	$58.6
Share	17.5%	81.6%	0.6%	0.0%	0.3%	100.0%	12.0%	87.0%	0.7%	0.0%	0.3%	100.0%

25 Table 4-27 includes all categories of charges as defined in Table 4-25 and Table 4-26 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 October 9, 2020. The 2020 uplift charges differ from the 2020 uplift credits by $0.02 million in the PJM data although they should be equal.

Table 4-25 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.[26] [27] Day-ahead operating reserve charges decreased by $6.9 million or 49.6 percent in the first nine months of 2020 compared to the first nine months of 2019. Day-ahead operating reserve charges decreased in 2020 as a result of a decrease in day-ahead unit commitments for reliability. The decrease in day-ahead operating reserve credits paid to units in Pepco and BGE accounted for 92.1 percent of the total decrease in day-ahead operating reserve charges during the first nine months of 2020 compared to the first nine months of 2019.

Table 4-25 Day-ahead operating reserve charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Day-Ahead Operating Reserve Charges	$14.0	$7.0	($6.9)	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$14.0	$7.0	($6.9)	100.0%	100.0%

Table 4-26 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $4.9 million or 8.7 percent in the first nine months of 2020 compared to 2019.

Table 4-26 Balancing operating reserve charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Balancing Operating Reserve Reliability Charges	$17.0	$11.9	($5.1)	30.5%	23.4%
Balancing Operating Reserve Deviation Charges	$36.2	$36.9	$0.8	64.7%	72.4%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$2.7	$2.2	($0.5)	4.8%	4.3%
Total	$55.9	$51.0	($4.8)	100.0%	100.0%

26 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.
27 See the *2020 Quarterly State of the Market Report for PJM: January through September*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-27 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 nine months of 2020, energy lost opportunity cost deviation charges increased by $4.6 million or 36.4 percent, and make whole deviation charges decreased by $3.8 million or 16.1 percent compared to the first nine months of 2019. The decrease in charges was the result of the significant decrease in balancing credits to generators.

Table 4-27 Balancing operating reserve deviation charges: January through September, 2019 and 2020

Charge Attributable To	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Make Whole Payments to Generators and Imports	$23.7	$19.9	($3.8)	65.4%	53.8%
Energy Lost Opportunity Cost	$12.5	$17.1	$4.6	34.6%	46.2%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$36.2	$36.9	$0.8	100.0%	100.0%

Table 4-28 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $0.1 million or 11.5 percent in the first nine months of 2020, compared to the first nine months of 2019.

Table 4-28 Additional energy uplift charges: January through September, 2019 and 2020

Type	(Jan - Sep) 2019 Charges (Millions)	(Jan - Sep) 2020 Charges (Millions)	Change (Millions)	(Jan - Sep) 2019 Share	(Jan - Sep) 2020 Share
Reactive Services Charges	$0.5	$0.4	($0.1)	72.6%	72.1%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.2	$0.2	($0.0)	27.4%	27.9%
Total	$0.6	$0.6	($0.1)	100.0%	100.0%

Table 4-29 and Table 4-30 show the amount and shares of regional balancing charges in the first nine months of 2019 and 2020. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In the first nine months of 2020, the largest share of regional charges was paid by real-time load which paid 23.2 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 nine months of 2020, regional balancing operating reserve charges decreased by $4.4 million compared to the first nine months of 2019. Balancing operating reserve reliability charges decreased by $5.1 million or 29.9 percent, and balancing operating reserve deviation charges increased by $0.7 million, or 1.9 percent.

Table 4-29 Regional balancing charges allocation (Millions): January through September, 2019

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$14.8	27.8%	$1.1	2.1%	$0.5	0.9%	$16.4	30.8%
	Real-Time Exports	$0.6	1.1%	$0.0	0.1%	$0.0	0.0%	$0.6	1.2%
	Total	$15.4	28.9%	$1.1	2.1%	$0.5	0.9%	$17.0	31.9%
Deviation Charges	Demand	$21.2	39.7%	$0.8	1.6%	$0.3	0.6%	$22.3	41.9%
	Supply	$5.6	10.5%	$0.3	0.5%	$0.1	0.2%	$6.0	11.2%
	Generator	$7.5	14.0%	$0.4	0.7%	$0.1	0.2%	$7.9	14.9%
	Total	$34.2	64.3%	$1.5	2.8%	$0.6	1.0%	$36.3	68.1%
Total Regional Balancing Charges		$49.6	93.2%	$2.6	4.9%	$1.0	2.0%	$53.3	100%

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

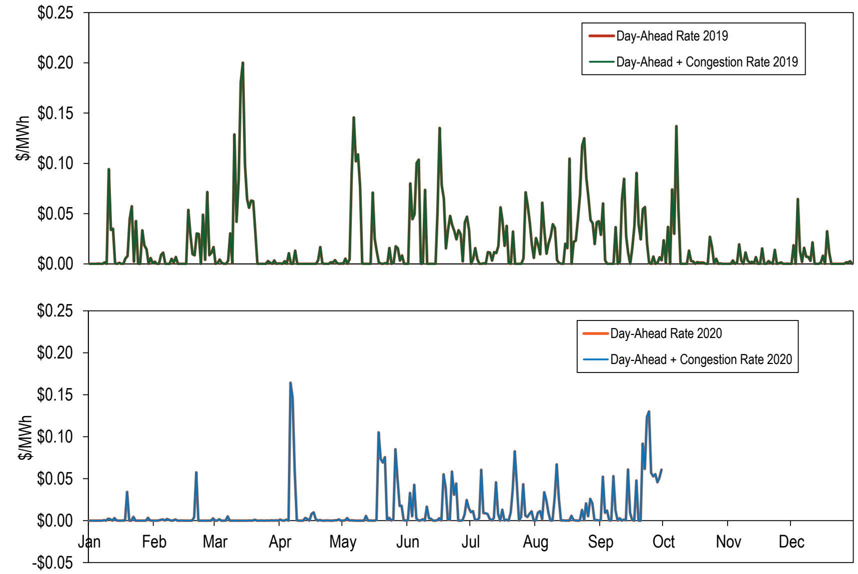
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$9.1	18.7%	$2.0	4.1%	$0.2	0.5%	$11.4	23.2%
	Real-Time Exports	$0.5	1.0%	$0.1	0.1%	$0.0	0.0%	$0.6	1.2%
	Total	$9.6	19.6%	$2.1	4.2%	$0.3	0.5%	$11.9	24.4%
Deviation Charges	Demand	$22.9	46.8%	$1.4	2.8%	$0.3	0.5%	$24.5	50.2%
	Supply	$4.3	8.8%	$0.3	0.7%	$0.0	0.1%	$4.7	9.6%
	Generator	$7.3	14.8%	$0.4	0.8%	$0.1	0.2%	$7.8	15.9%
	Total	$34.4	70.4%	$2.1	4.4%	$0.4	0.8%	$37.0	75.6%
Total Regional Balancing Charges		$44.0	90.1%	$4.2	8.6%	$0.6	1.3%	$48.9	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 4-21 shows how these charges are allocated.[28]

Figure 4-2 shows the daily day-ahead operating reserve rate for 2019 and 2020. The average rate in the first nine months of 2020 was $0.012 per MWh, $0.011 per MWh lower than the average in the first nine months of 2019. The highest rate in the first nine months of 2020 occurred on April 6, when units were called on by reliability engineers due to transmission constraints, and the rate reached $0.164 per MWh, $0.036 per MWh lower than the $0.200 per MWh reached in the first nine months of 2019, on March 15. 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 2019 or 2020.

Figure 4-2 Daily day-ahead operating reserve rate ($/MWh): 2019 through September 2020



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

Figure 4-3 shows the RTO and the regional reliability rates for 2019 and the first nine months of 2020. The average RTO reliability rate in 2020 was $0.016 per MWh. The highest RTO reliability rate in 2020 occurred on June 10, when the rate reached $0.152 per MWh, $0.216 per MWh lower than the $0.368 per MWh rate reached in the first nine months of 2019, on January 22.

Figure 4-3 Daily balancing operating reserve reliability rates ($/MWh): 2019 through September 2020

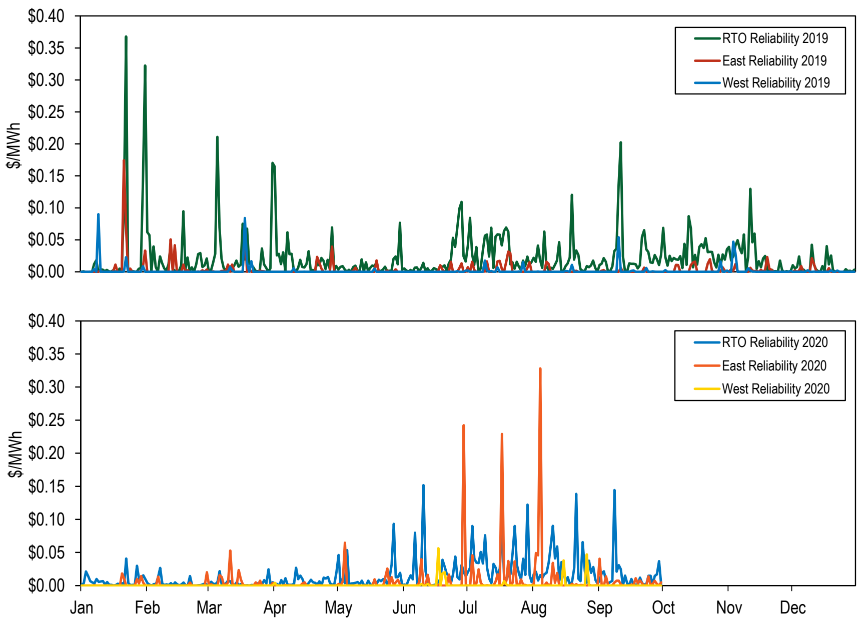


Figure 4-4 shows the RTO and regional deviation rates for 2019 and the first nine months of 2020. The average RTO deviation rate in 2020 was $0.149 per MWh. The highest daily rate in the first nine months of 2020 occurred on August 21, when the RTO deviation rate reached $1.224 per MWh, $0.002 per MWh less than the $1.226 per MWh rate reached in 2019, on July 9.

Figure 4-4 Daily balancing operating reserve deviation rates ($/MWh): 2019 through September 2020

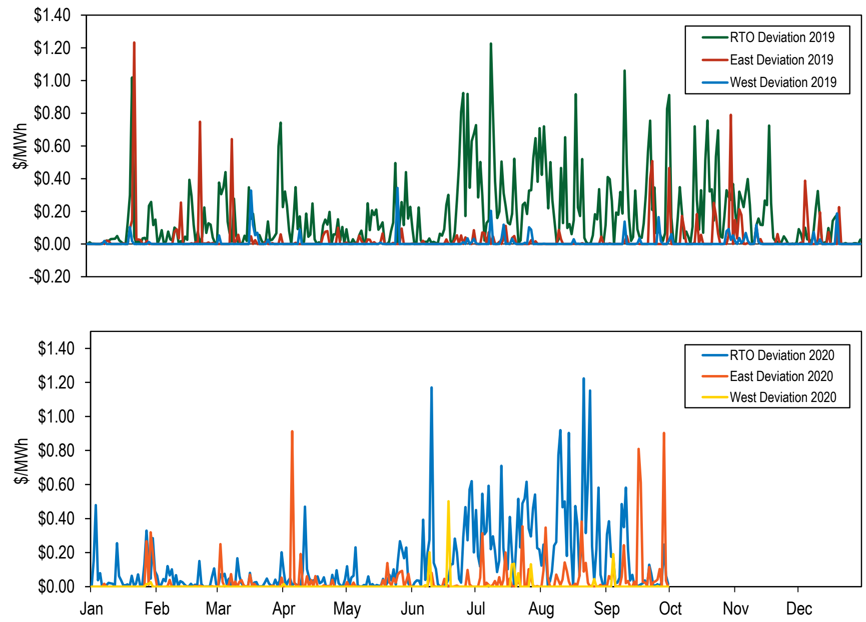


Figure 4-5 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2019 and the first nine months of 2020. The average lost opportunity cost rate in 2020 was $0.147 per MWh. The highest lost opportunity cost rate in the first nine months of 2020 occurred on June 3, when it reached $1.923 per MWh, $0.125 per MWh lower than the $2.049 per MWh rate reached in 2019, on May 22.

Figure 4-5 Daily lost opportunity cost and canceled resources rates ($/MWh): 2019 through September 2020

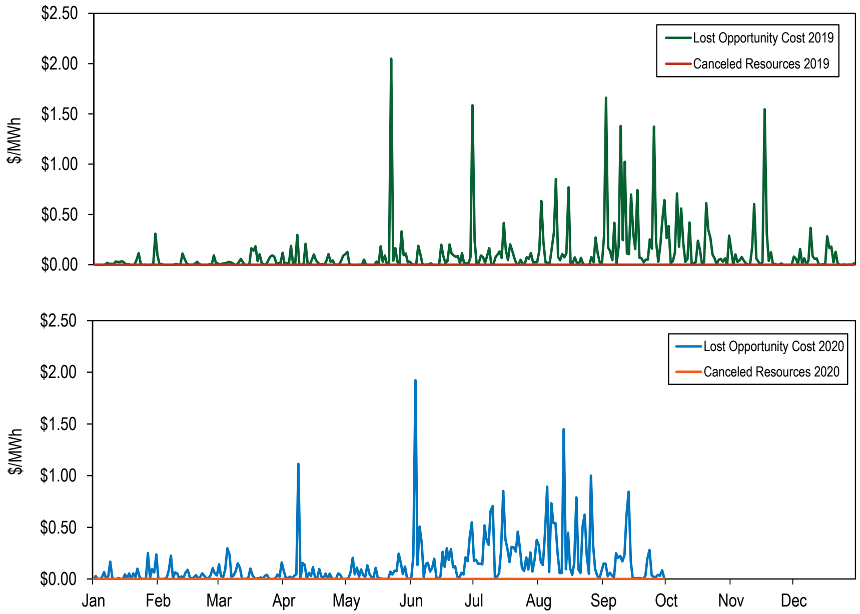


Table 4-31 shows the average rates for each region in each category for the first nine months of 2019 and 2020.

Table 4-31 Operating reserve rates ($/MWh): January through September, 2019 and 2020

Rate	(Jan - Sep) 2019 ($/MWh)	(Jan - Sep) 2020 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.022	0.012	(0.011)	(47.7%)
Day-Ahead with Unallocated Congestion	0.022	0.012	(0.011)	(47.7%)
RTO Reliability	0.025	0.016	(0.009)	(35.5%)
East Reliability	0.004	0.007	0.004	90.0%
West Reliability	0.002	0.001	(0.001)	(47.6%)
RTO Deviation	0.185	0.149	(0.036)	(19.5%)
East Deviation	0.025	0.038	0.013	50.9%
West Deviation	0.010	0.007	(0.003)	(31.6%)
Lost Opportunity Cost	0.107	0.147	0.040	37.3%
Canceled Resources	0.000	0.000	NA	NA

Table 4-32 shows the operating reserve cost of a one MW transaction in the first nine months of 2020. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.345 per MWh with a maximum rate of $1.966 per MWh, a minimum rate of $0.001 per MWh and a standard deviation of $0.360 per MWh. The rates in Table 4-32 include all operating reserve charges including RTO deviation charges. Table 4-32 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 and DECs have higher rates compared to real-time load because they are allocated a deviation charge while day-ahead and real-time load do not necessarily incur a deviation charge.

Table 4-32 Operating reserve rates statistics ($/MWh): January through September, 2020

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	1.961	0.333	<0.001	0.358
	DEC	1.966	0.345	0.001	0.360
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.344	0.024	<0.001	0.040
	Deviation	1.961	0.333	<0.001	0.358
West	INC	1.961	0.302	<0.001	0.338
	DEC	1.966	0.314	<0.001	0.340
	DA Load	0.164	0.012	<0.001	0.025
	RT Load	0.152	0.017	<0.001	0.024
	Deviation	1.961	0.302	<0.001	0.338

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.[29] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-33 shows the reactive services rates associated with local voltage support in the first nine months of 2019 and 2020. Table 4-33 shows that in the first nine months of 2020 only five zones incurred reactive charges, in addition to reactive capability charges. Real-time load in the JCPL Zone, where reactive service charges were the highest, paid an average of $0.010 per MWh for reactive services, and real-time load in the PPL Control Zone, where charges were the second highest, paid an average of $0.006 per MWh for reactive services.

Table 4-33 Local voltage support rates: January through September, 2019 and 2020

Control Zone	(Jan - Sep) 2019 ($/MWh)	(Jan - Sep) 2020 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	(0.000)	(100.0%)
APS	0.000	0.000	(0.000)	(100.0%)
ATSI	0.000	0.000	(0.000)	(100.0%)
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	0.002	0.000	(0.002)	(100.0%)
DPL	0.007	0.001	(0.007)	(92.6%)
EKPC	0.000	0.005	0.005	NA
JCPL	0.000	0.010	0.010	NA
Met-Ed	0.000	0.000	0.000	NA
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PENELEC	0.011	0.000	(0.011)	(100.0%)
Pepco	0.000	0.000	0.000	0.0%
PPL	0.000	0.006	0.006	NA
PSEG	0.000	0.000	0.000	0.0%
RECO	0.000	0.000	0.000	0.0%

29 See *2019 State of the Market Report for PJM*, Volume 2, Section 10: Ancillary Service Markets.

Balancing Operating Reserve Determinants

Table 4-34 shows the determinants used to allocate the regional balancing operating reserve charges in the first nine months of 2019 and 2020. Total real-time load and real-time exports were 594,486 GWh, 3.7 percent lower in 2020 compared to 2019. Total deviations summed across the demand, supply, and generator categories were 116,337 GWh, 1.0 percent lower in the first nine months of 2020 compared to the first nine months of 2019.

Table 4-34 Balancing operating reserve determinants (GWh): January through September, 2019 and 2020

		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 - Sep) 2019	RTO	590,833	26,274	617,108	71,103	20,835	25,548	117,487
	East	282,332	11,440	293,772	34,611	11,297	13,033	58,941
	West	308,502	14,834	323,335	35,909	9,077	12,516	57,501
(Jan - Sep) 2020	RTO	564,700	29,786	594,486	74,144	17,053	25,140	116,337
	East	270,505	9,646	280,152	35,611	9,586	11,454	56,651
	West	294,194	20,140	314,334	38,174	7,272	13,686	59,132
Difference	RTO	(26,134)	3,512	(22,622)	3,041	(3,782)	(408)	(1,149)
	East	(11,827)	(1,794)	(13,620)	1,001	(1,711)	(1,578)	(2,289)
	West	(14,307)	5,306	(9,001)	2,265	(1,805)	1,170	1,631

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 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 4-35 shows the different categories by type of transactions that incurred deviations. In the first nine months of 2020, 31.8 percent of all RTO deviations were incurred by either virtual transactions, or by a combined transaction that includes virtuals, such as combinations with exports and load. The remaining 68.2 percent of all RTO deviations were incurred by transaction types not involving virtuals. Combined transactions with virtuals incur higher deviations than those without.

Table 4-35 Deviations by transaction type: January through September, 2020

Deviation Category	Transaction	Deviation (GWh) RTO	East	West	Share RTO	East	West
Demand	DECs Only	19,537	10,332	8,846	16.8%	18.2%	15.0%
	Exports Only	5,762	2,371	3,391	5.0%	4.2%	5.7%
	Load Only	46,324	22,736	23,587	39.8%	40.1%	39.9%
	Combination with DECs	2,511	161	2,350	2.2%	0.3%	4.0%
	Combination without DECs	11	11	0	0.0%	0.0%	0.0%
Supply	Imports Only	2,126	1,745	381	1.8%	3.1%	0.6%
	INCs Only	14,766	7,681	6,890	12.7%	13.6%	11.7%
	Combination with INCs	161	160	2	0.1%	0.3%	0.0%
	Combination without INCs	0	0	0	0.0%	0.0%	0.0%
Generators		25,140	11,454	13,686	21.6%	20.2%	23.1%
Total		116,337	56,651	59,132	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-36 shows the geography of charges and credits in the first nine months of 2020. Table 4-36 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 5.5 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 1.8 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 10.7 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 4.1 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 11.7 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 22.0 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-36 also shows that 88.8 percent of all charges were allocated in control zones, 3.9 percent in hubs and aggregates and 7.3 percent in interfaces.

Table 4-36 Geography of regional charges and credits: January through September, 2020

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$0.8	$1.0	$0.1	1.4%	1.7%	0.0%	0.7%
	AEP	$7.4	$8.1	$0.8	13.2%	14.6%	0.0%	4.0%
	APS	$2.8	$1.2	($1.7)	5.1%	2.1%	8.7%	0.0%
	ATSI	$3.6	$2.7	($0.9)	6.5%	4.9%	4.8%	0.0%
	BGE	$2.3	$6.5	$4.3	4.1%	11.7%	0.0%	22.0%
	ComEd	$6.0	$14.6	$8.7	10.7%	26.2%	0.0%	44.9%
	DAY	$0.8	$1.2	$0.4	1.4%	2.1%	0.0%	1.9%
	DEOK	$1.6	$1.1	($0.5)	2.8%	2.0%	2.4%	0.0%
	DLCO	$0.9	$0.1	($0.7)	1.5%	0.2%	3.9%	0.0%
	Dominion	$5.9	$6.9	$1.0	10.6%	12.3%	0.0%	5.1%
	DPL	$1.5	$3.1	$1.6	2.6%	5.5%	0.0%	8.5%
	EKPC	$0.6	$1.4	$0.8	1.1%	2.5%	0.0%	4.1%
	External	$0.0	$1.4	$1.4	0.0%	2.6%	0.0%	7.4%
	JCPL	$1.6	$1.1	($0.5)	2.9%	2.0%	2.4%	0.0%
	Met-Ed	$1.2	$0.5	($0.7)	2.1%	1.0%	3.4%	0.0%
	OVEC	$0.2	$0.0	($0.2)	0.4%	0.0%	1.1%	0.0%
	PECO	$2.6	$0.1	($2.5)	4.6%	0.1%	13.1%	0.0%
	PENELEC	$1.9	$0.8	($1.1)	3.4%	1.5%	5.6%	0.0%
	Pepco	$2.2	$2.4	$0.2	3.9%	4.4%	0.0%	1.3%
	PPL	$3.0	$1.0	($2.1)	5.5%	1.8%	10.7%	0.0%
	PSEG	$2.7	$0.6	($2.1)	4.8%	1.1%	10.8%	0.0%
	RECO	$0.2	$0.0	($0.2)	0.3%	0.0%	0.8%	0.0%
	All Zones	$49.6	$55.9	$6.3	88.8%	100.0%	67.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.5	$0.0	($0.5)	0.8%	0.0%	2.4%	0.0%
	Dominion	$0.2	$0.0	($0.2)	0.3%	0.0%	0.9%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.2%	0.0%	0.7%	0.0%
	New Jersey	$0.3	$0.0	($0.3)	0.5%	0.0%	1.4%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.2%	0.0%	0.5%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$1.0	$0.0	($1.0)	1.9%	0.0%	5.4%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$2.2	$0.0	($2.2)	3.9%	0.0%	11.4%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	CPLE Imp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	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%	0.1%	0.0%
	Hudson	$0.2	$0.0	($0.2)	0.4%	0.0%	1.2%	0.0%
	IMO	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	Linden	$0.3	$0.0	($0.3)	0.5%	0.0%	1.5%	0.0%
	MISO	$2.0	$0.0	($2.0)	3.5%	0.0%	10.2%	0.0%
	NCMPA Imp	$0.1	$0.0	($0.1)	0.2%	0.0%	0.7%	0.0%
	Neptune	$0.2	$0.0	($0.2)	0.3%	0.0%	1.0%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.2	$0.0	($0.2)	0.4%	0.0%	1.1%	0.0%
	NYIS	$0.4	$0.0	($0.4)	0.6%	0.0%	1.8%	0.0%
	South Exp	$0.3	$0.0	($0.3)	0.6%	0.0%	1.6%	0.0%
	South Imp	$0.3	$0.0	($0.3)	0.5%	0.0%	1.4%	0.0%
	All Interfaces	$4.1	$0.0	($4.1)	7.3%	0.0%	21.0%	0.0%
	Total	$55.9	$55.9	$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).[30] 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 4-37 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first nine months of 2019, balancing operating reserve credits would have been $10.0 million or 24.6 percent lower if they were calculated on a daily basis. In the first nine months of 2020, balancing operating reserve credits would have been $8.1 million or 25.5 percent lower if they were calculated on a daily basis.

Table 4-37 Intraday segments and daily balancing operating reserve credits: January 2019 through September 2020

	2019 BOR Credits (Millions)			2020 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$5.4	$4.6	($0.8)	$1.6	$1.3	($0.3)
Feb	$2.5	$2.3	($0.3)	$0.7	$0.5	($0.2)
Mar	$3.6	$2.9	($0.7)	$0.9	$0.7	($0.2)
Apr	$3.5	$2.9	($0.6)	$1.1	$0.9	($0.2)
May	$2.3	$1.7	($0.5)	$1.9	$1.6	($0.3)
Jun	$4.1	$3.3	($0.8)	$5.1	$4.1	($1.0)
Jul	$8.7	$6.0	($2.7)	$8.8	$5.7	($3.1)
Aug	$5.1	$3.0	($2.0)	$8.1	$6.1	($2.1)
Sep	$5.7	$4.0	($1.7)	$3.6	$2.8	($0.7)
Oct	$5.9	$4.5	($1.4)			
Nov	$3.9	$2.5	($1.4)			
Dec	$1.7	$1.2	($0.5)			
Total (Jan - Sep)	$40.7	$30.7	($10.0)	$31.8	$23.7	($8.1)
Total	$52.1	$38.9	($13.3)	$31.8	$23.7	($8.1)

30 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 4-38 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 nine months of 2020, LOC credits would have been 7.4 percent lower if they had been settled on an hourly basis rather than on a five minute basis. For the first nine months of 2020, LOC credits would have been $3.0 million or 18.8 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute settlement.

Table 4-38 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through September, 2020

	2020 Day Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$0.5	$0.5	$0.1	$0.5	$0.0
Feb	$0.4	$0.4	($0.0)	$0.3	($0.1)
Mar	$0.6	$0.5	($0.1)	$0.5	($0.1)
Apr	$0.3	$0.3	($0.0)	$0.3	($0.1)
May	$0.8	$0.8	($0.0)	$0.6	($0.2)
Jun	$3.3	$3.1	($0.2)	$2.8	($0.4)
Jul	$4.2	$3.8	($0.4)	$3.2	($1.0)
Aug	$4.5	$4.2	($0.3)	$3.8	($0.7)
Sep	$1.6	$1.4	($0.2)	$1.2	($0.5)
Total (Jan - Sep)	$16.1	$15.0	($1.2)	$13.1	($3.0)

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.[31] 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 4-39 shows that during the first nine months of 2020, 81.9 percent of uplift credits were paid to units that were committed and dispatched on price offers without parameter limits, 11.7 percent to units committed on cost-based offers, 5.7 percent were committed on price-based offers with limited parameters (PLS) and 0.7 percent to units committed on a combination of price-based and cost-based offers.

Table 4-39 Operating Reserve Credits by Offer Type: January through September, 2020

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	$3.8	$0.0	$0.3
Price	$6.4	$25.6	$0.0	$0.0
Price PLS	$0.2	$2.1	$0.0	$0.0
Cost & Price	$0.0	$0.2	$0.0	$0.0
Cost & PLS	$0.0	$0.1	$0.0	$0.0
Price & PLS	$0.0	$0.0	$0.0	$0.0
Total	$7.0	$31.7	$0.1	$0.3

31 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>.