Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required 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 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 at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.

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.

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 should nonetheless 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 in accordance with 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.

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $96.7 million, or 194.8 percent, in the first six months of 2018 compared to the first six months of 2017, from $49.7 million to $146.4 million.
- **Energy Uplift Charges Categories.** The increase of $96.7 million in the first six months of 2018 is comprised of a $19.4 million increase in day-ahead operating reserve charges, a $76.14 million increase in balancing operating reserve charges and a $1.4 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.063 per MWh, real-time load paid $0.070 per MWh, a DEC paid $0.969 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.907 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.063 per MWh, real-time load paid $0.068 per MWh, a DEC paid $1.043 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.980 per MWh.
- **Reactive Services Rates.** The ComEd, EKPC, and PENELEC control zones had the three highest local voltage support rates: $0.112, $0.021 and $0.004 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 58.6 percent of all day-ahead generator credits and 86.8 percent of all reactive service credits. Combustion turbines received 56.0 percent of all balancing generator credits. Combustion turbines and diesels received 73.0 percent of the lost opportunity cost credits.

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.

- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 29.0 percent of all credits. The top 10 organizations received 78.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7990, balancing operating reserves HHI was 3506 and lost opportunity cost HHI was 4349.
- **Economic and Noneconomic Generation.** In the first six months of 2018, 85.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 69.6 percent of the real-time generation eligible for operating reserve credits was economic.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $36.2 million or 640.1 percent, in the first six months of 2018 compared to the first six months of 2018, from $5.7 million to $41.9 million, as result of units scheduled in day-ahead and not taken in real time.
- **Day-ahead generation not requested in real time.** Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time receiving lost opportunity cost credits increased by 516 GWh or 267 percent in the first six months of 2018, compared to the first six months of 2017, from 193 GWh to 709 GWh.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2018, 1.9 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.0 percent received energy uplift payments.

Geography of Charges and Credits

- In the first six months of 2018, 88.3 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generation, 2.8 percent by transactions at hubs and aggregates and 8.8 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 57.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 40.9 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- The MMU recommends that uplift should only be paid 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 Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported 2016. Status: Not adopted.)

- The MMU recommends that PJM initiate an analysis of the reasons why some 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: Not adopted.)
- The MMU recommends eliminating the use of intraday segments to define eligibility for uplift payments and returning to evaluating the need for uplift on a daily, 24 hours, basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category 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. Stakeholder process.)
- 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. Stakeholder process.)
- The MMU recommends not compensating self scheduled units 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 four additional 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 units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. 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. Pending before FERC.)
- 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: Not adopted. Pending before FERC.)
- 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 operating reserve credits 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, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends enhancing the current energy uplift allocation rules to reflect the 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 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 submit 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 revise Manual 11 attachment C consistent with the tariff to limit uplift compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Adopted 2015.)
- 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.)
- The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Status: Adopted 2015.)
- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Status: Adopted 2015.)
- 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 Q1, 2018. Status: Not adopted.)
- The MMU recommends implementation of a metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)

Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss incurred when LMP is greater than or equal to the incremental offer but does not cover start up and no load costs. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market at short run marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges, black start charges, or energy payments to demand response resources.

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But 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. PJM has failed to hold coal, gas and oil steam turbines to the standard used for combined cycles, combustion turbines and diesels. The standard 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 to steam units 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.

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.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. 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 and that the allocation of these charges reflects the reasons that the costs are incurred, to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. 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 for more than ten years.

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.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. For example, up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.[4] Some

4 On October 17, 2017, PJM filed with FERC to begin charging uplift to UTC transactions and eliminating the netting of deviations with internal bilateral transactions. See FERC Docket No. ER18-86-000.

uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market if the unit is to receive uplift payments from other market participants. 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.

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

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 price setting logic. The same is true of fast start pricing and of convex hull pricing.

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 would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would 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 would be created in more limited form by PJM's fast start pricing proposal (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

Energy Uplift

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 hourly LMP is less than the offer price including incremental, no load and startup costs.

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 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 4-1 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	in RTO, Eastern or Western Region
			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	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Real-Time Import Transactions	Balancing Operating Reserve Transaction	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

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

Energy Uplift Results[5]

Energy Uplift Charges

Table 4-3 shows total energy uplift charges by category in the first six months of 2017 and 2018.[6] Total energy uplift charges increased by $96.7 million or 194.8 percent in the first six months of 2018 compared to the first six months of 2017. The increase of $96.7 million is comprised of an increase of $19.4 million in day-ahead operating reserve charges, an increase of $76.1 million in balancing operating reserve charges and an increase of $1.4 million in reactive service charges.

Table 4-3 Total energy uplift charges by category: January through June, 2017 and 2018

Category	(Jan - Jun) 2017 Charges (Millions)	(Jan - Jun) 2018 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$8.6	$27.9	$19.4	226.0%
Balancing Operating Reserves	$31.6	$107.7	$76.1	240.8%
Reactive Services	$9.3	$10.7	$1.4	14.5%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.1	$0.0	($0.1)	(84.1%)
Total	$49.7	$146.4	$96.7	194.8%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.6%	0.3%	116.7%

Table 4-4 compares monthly energy uplift charges by category for 2017 and 2018.

Table 4-4 Monthly energy uplift charges: January 2017 through June 2018

	2017 Charges (Millions)						2018 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	$2.6	$7.5	$1.3	$0.0	$0.0	$11.4	$4.8	$55.4	$1.94	$0.0	$0.0	$62.1
Feb	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6	$3.6	$1.9	$2.2	$0.0	$0.0	$7.8
Mar	$0.6	$5.4	$1.4	$0.0	$0.0	$7.4	$4.6	$6.4	$1.9	$0.0	$0.0	$12.9
Apr	$0.5	$3.3	$1.3	$0.0	$0.0	$5.1	$2.1	$9.6	$1.2	$0.0	$0.0	$12.9
May	$0.9	$7.4	$1.3	$0.0	$0.0	$9.7	$7.1	$17.6	$2.2	$0.0	$0.0	$26.9
Jun	$1.8	$6.8	$0.9	$0.0	$0.0	$9.5	$5.8	$16.8	$1.3	$0.0	$0.0	$23.9
Jul	$2.5	$7.9	$0.9	$0.0	$0.0	$11.4						
Aug	$2.9	$5.4	$1.5	$0.0	$0.0	$9.8						
Sep	$3.0	$10.3	$2.3	$0.0	$0.0	$15.6						
Oct	$1.6	$7.9	$2.2	$0.0	$0.0	$11.8						
Nov	$2.1	$7.7	$1.9	$0.0	$0.0	$11.8						
Dec	$4.0	$12.8	$2.3	$0.0	$0.0	$19.1						
Total (Jan - Jun)	$8.6	$31.6	$9.3	$0.0	$0.1	$49.7	$27.9	$107.7	$10.7	$0.0	$0.0	$146.4
Share (Jan - Jun)	17.3%	63.6%	18.8%	0.0%	0.3%	100.0%	19.1%	73.6%	7.3%	0.0%	0.0%	100.0%
Total	$24.8	$83.7	$20.4	$0.0	$0.3	$129.1	$27.9	$107.7	$10.7	$0.0	$0.0	$146.4
Share	19.2%	64.8%	15.8%	0.0%	0.2%	100.0%	19.1%	73.6%	7.3%	0.0%	0.0%	100.0%

5 In May and June of 2018 $13.8 million in local constraint credits were incorrectly categorized by PJM as balancing operating reserve credits. As of July 27, 2018, a resettlement is pending. Once the resettlement is effected, the regional balancing operating reserve rates will change.

6 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 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 July 24, 2018.

Table 4-5 shows the composition of the 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.[7] Day-ahead operating reserve charges increased by $19.4 million or 226.4 percent in the first six months of 2018 compared to the first six months of 2017. Day-ahead operating reserve charges increased in the first six months of 2018 due to reliability issues in the BGE and Pepco control zones as a result of new flow patterns, voltage issues in the ComEd Zone, and the high load in early January which required additional commitments in the Day-Ahead Energy Market.

Table 4-5 Day-ahead operating reserve charges: January through June, 2017 and 2018

Type	(Jan - Jun) 2017 Charges (Millions)	(Jan - Jun) 2018 Charges (Millions)	Change (Millions)	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Day-Ahead Operating Reserve Charges	$8.6	$27.9	$19.4	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	$8.6	$27.9	$19.4	100.0%	100.0%

Table 4-6 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $76.1 million in the first six months of 2018 compared to the first six months of 2017.

Table 4-6 Balancing operating reserve charges: January through June, 2017 and 2018

Type	(Jan - Jun) 2017 Charges (Millions)	(Jan - Jun) 2018 Charges (Millions)	Change (Millions)	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Balancing Operating Reserve Reliability Charges	$10.2	$31.3	$21.2	32.1%	29.1%
Balancing Operating Reserve Deviation Charges	$20.9	$76.3	$55.4	66.1%	70.9%
Balancing Operating Reserve Charges for Load Response	$0.2	$0.0	($0.2)	0.6%	0.0%
Balancing Local Constraint Charges	$0.4	$0.0	($0.3)	1.1%	0.0%
Total	$31.6	$107.7	$76.1	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions; energy lost opportunity costs paid to generators; and payments to resources canceled by PJM before coming online. In the first six months of 2018, 45.1 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 27.6 percentage points in the share of balancing operating reserve deviation charges compared to the first six months of 2017. Energy lost opportunity cost credits increased by $36.2 million or 635.1 percent, and make whole credits increased by $19.2 million or 126.7 percent.

7 See OA 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 10 times, totaling $26.9 million.

Table 4-7 Balancing operating reserve deviation charges: January through June, 2017 and 2018

Charge Attributable To	(Jan - Jun) 2017 Charges (Millions)	(Jan - Jun) 2018 Charges (Millions)	Change (Millions)	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Make Whole Payments to Generators and Imports	$15.2	$34.4	$19.2	72.6%	45.1%
Energy Lost Opportunity Cost	$5.7	$41.9	$36.2	27.3%	54.9%
Canceled Resources	$0.0	$0.0	($0.0)	0.1%	0.0%
Total	$20.9	$76.3	$55.4	100.0%	100.0%

Table 4-8 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $1.4 million in the first six months of 2018, compared to first six months of 2017, as a result of high voltage issues in the ComEd and DPL control zones, and low voltage issues in the PENELEC and AEP control zones.

Table 4-8 Additional energy uplift charges: January through June, 2017 and 2018

Type	(Jan - Jun) 2017 Charges (Millions)	(Jan - Jun) 2018 Charges (Millions)	Change (Millions)	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Reactive Services Charges	$9.3	$10.7	$1.4	98.5%	99.4%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.4%
Black Start Services Charges	$0.1	$0.0	($0.1)	1.5%	0.2%
Total	$9.5	$10.8	$1.3	100.0%	100.0%

Table 4-9 and Table 4-10 show the amount and shares of regional balancing charges in the first three months of 2017 and 2018. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first six months of 2018, regional balancing operating reserve charges increased by $76.2 million compared to the first six months of 2017. Balancing operating reserve reliability charges increased by $20.8 million, or 204.6 percent, and balancing operating reserve deviation charges increased by $55.4 million, or 264.2 percent.

Table 4-9 Regional balancing charges allocation (Millions): January through June, 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$8.8	28.4%	$0.9	2.8%	$0.1	0.2%	$9.8	31.4%
	Real-Time Exports	$0.3	1.1%	$0.0	0.1%	$0.0	0.0%	$0.4	1.2%
	Total	$9.2	29.5%	$0.9	2.9%	$0.1	0.2%	$10.2	32.6%
Deviation Charges	Demand	$11.8	37.9%	$0.4	1.3%	$0.1	0.2%	$12.3	39.4%
	Supply	$4.2	13.6%	$0.2	0.6%	$0.0	0.1%	$4.4	14.2%
	Generator	$4.1	13.2%	$0.1	0.4%	$0.0	0.1%	$4.3	13.7%
	Total	$20.1	64.7%	$0.7	2.3%	$0.1	0.3%	$21.0	67.4%
Total Regional Balancing Charges		$29.3	94.2%	$1.6	5.2%	$0.2	0.6%	$31.1	100%

Table 4-10 Regional balancing charges allocation (Millions): January through June, 2018

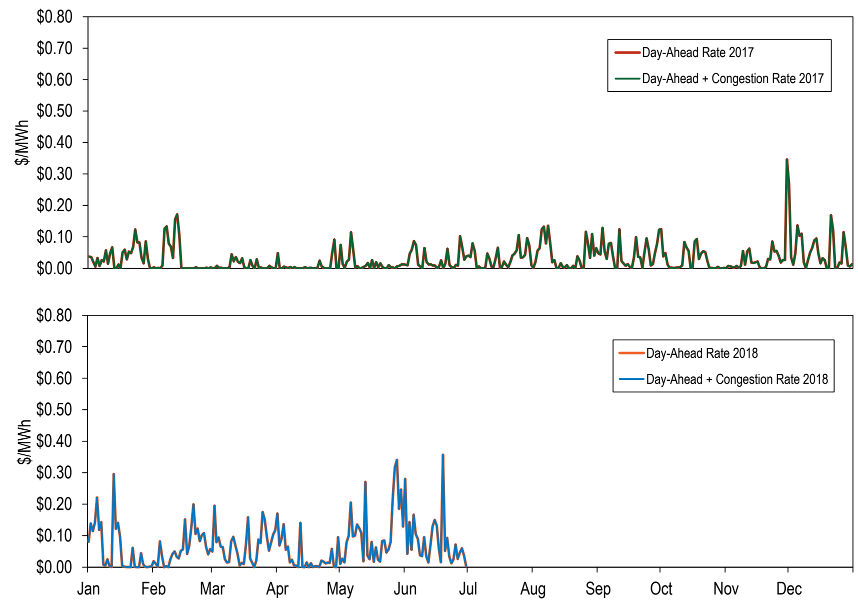
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$27.0	25.2%	$1.8	1.7%	$1.2	1.1%	$30.0	28.0%
	Real-Time Exports	$0.8	0.8%	$0.1	0.1%	$0.0	0.0%	$0.9	0.8%
	Total	$27.9	26.0%	$1.9	1.7%	$1.2	1.1%	$30.9	28.8%
Deviation Charges	Demand	$40.2	37.5%	$0.9	0.9%	$1.8	1.7%	$42.9	40.0%
	Supply	$12.9	12.0%	$0.4	0.4%	$0.5	0.5%	$13.8	12.9%
	Generator	$18.3	17.1%	$0.4	0.4%	$0.9	0.8%	$19.6	18.3%
	Total	$71.4	66.5%	$1.8	1.7%	$3.1	2.9%	$76.3	71.2%
Total Regional Balancing Charges		$99.3	92.5%	$3.7	3.4%	$4.3	4.0%	$107.3	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 4-1 shows how these charges are allocated.[8]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2017 and the six three months of 2018. The average rate in the first six months of 2018 was $0.070 per MWh, $0.048 per MWh higher than the average in the first six months of 2017. The highest rate of 2018 occurred on June 19, when the rate reached $0.357 per MWh, $0.185 per MWh higher than the $0.172 per MWh reached in the first six months of 2017, on February 12. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2017 or 2018.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): January 2017 through June 2018



8 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 4-2 shows the RTO and the regional reliability rates for 2017 and the first three months of 2018. The average RTO reliability rate in the first six months of 2018 was $0.071 per MWh. The highest RTO reliability rate in 2018 occurred on January 2, when the rate reached $0.731 per MWh, $0.341 per MWh higher than the $0.390 per MWh rate reached in the six months of 2017, on January 8.

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): January 2017 through June 2018

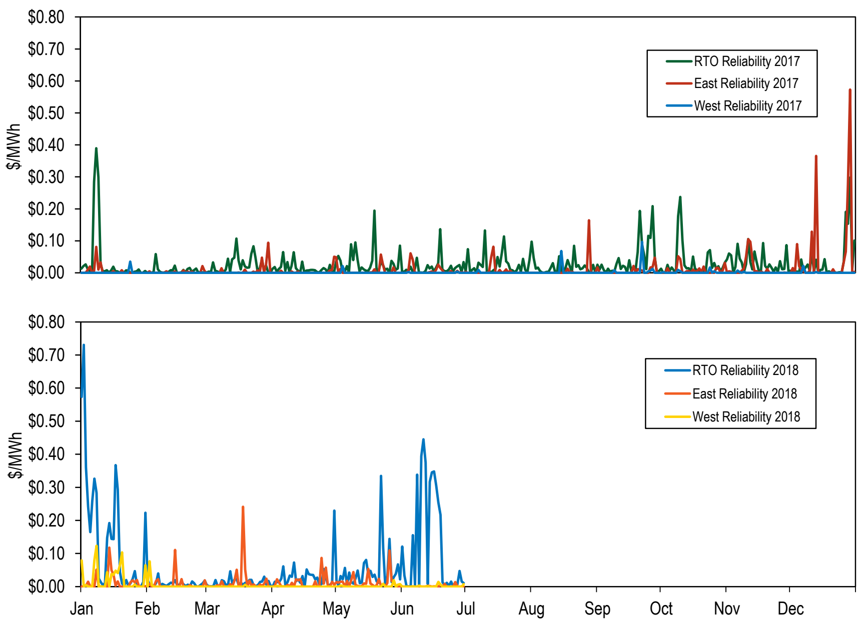


Figure 4-3 shows the RTO and regional deviation rates for 2017 and the first six months of 2018. The average RTO deviation rate in the first six months of 2018 was $0.388 per MWh. The highest daily rate of 2018 occurred on January 1, when the RTO deviation rate reached $4.488per MWh, $2.311 per MWh higher than the $2.177 per MWh rate reached in the first six months of 2017, on January 9.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): January 2017 through June 2018

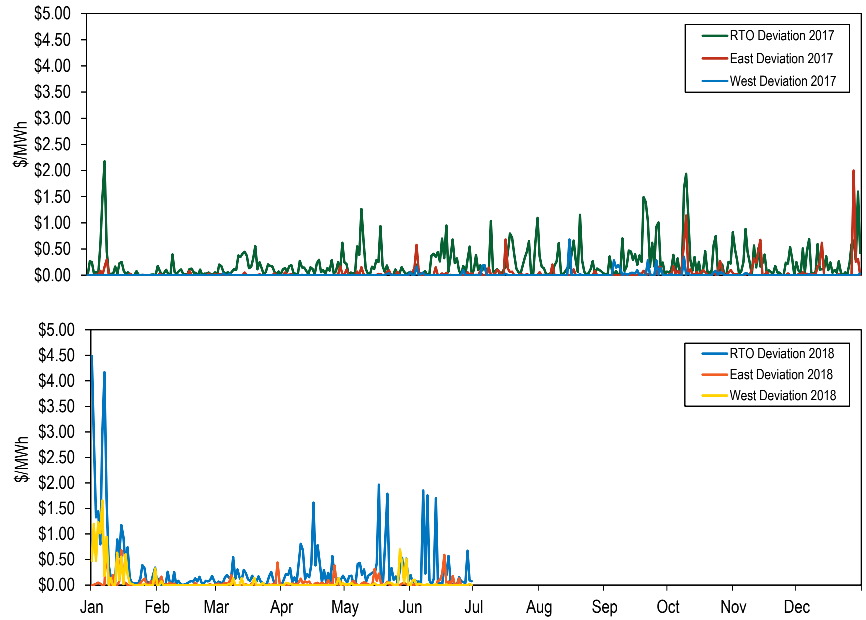


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2017 and the first six months of 2018. The average lost opportunity cost rate in the first six months was $0.552 per MWh. The highest lost opportunity cost rate occurred on January 7, when it reached $9.017 per MWh, $8.502 per MWh higher than the $0.514 per MWh rate reached in 2017, on March 13.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): January 2017 through June 2018

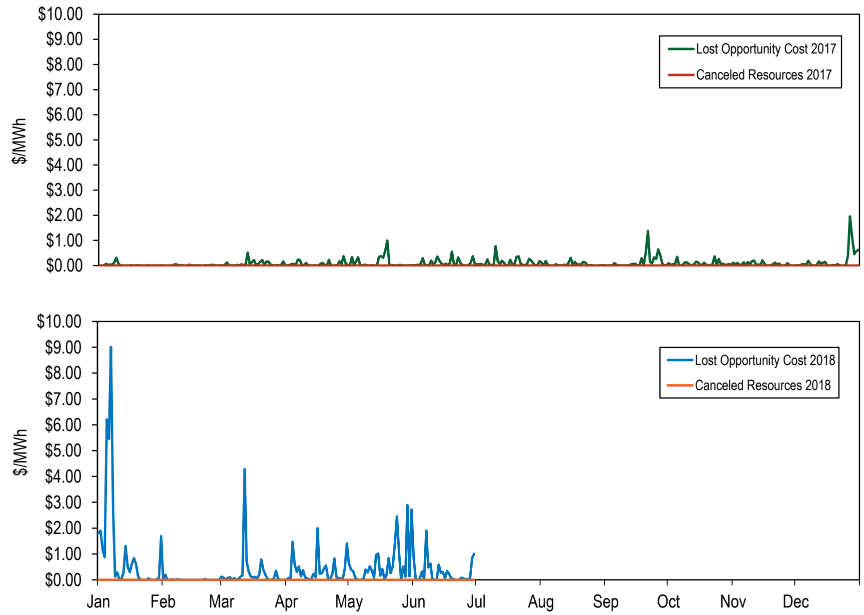


Table 4-11 shows the average rates for each region in each category for the first six months in 2017 and 2018.

Table 4-11 Operating reserve rates ($/MWh): January through June, 2017 and 2018

Rate	(Jan - Jun) 2017 ($/MWh)	(Jan - Jun) 2018 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.022	0.070	0.048	224.1%
Day-Ahead with Unallocated Congestion	0.022	0.070	0.048	224.1%
RTO Reliability	0.024	0.071	0.047	197.8%
East Reliability	0.005	0.010	0.005	98.8%
West Reliability	0.000	0.006	0.005	1,516.0%
RTO Deviation	0.188	0.388	0.200	106.9%
East Deviation	0.018	0.046	0.028	155.0%
West Deviation	0.003	0.087	0.084	3,027.0%
Lost Opportunity Cost	0.074	0.552	0.478	641.5%
Canceled Resources	0.000	-	(0.000)	

Table 4-12 shows the operating reserve cost of a one MW transaction in the first six months of 2018. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.969 per MWh with a maximum rate of $13.336 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $2.041 per MWh. The rates in Table 4-12 include all operating reserve charges including RTO deviation charges. Table 4-12 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-12 Operating reserve rates statistics ($/MWh): January through June, 2018

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	13.194	0.907	0.001	2.023
	DEC	13.336	0.969	0.026	2.041
	DA Load	0.296	0.063	0.000	0.060
	RT Load	0.733	0.070	0.000	0.130
	Deviation	13.194	0.907	0.001	2.023
West	INC	13.363	0.980	0.000	2.211
	DEC	13.505	1.043	0.017	2.231
	DA Load	0.296	0.063	0.000	0.060
	RT Load	0.731	0.068	0.000	0.138
	Deviation	13.363	0.980	0.000	2.211

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 revenue requirement charges which are a fixed annual charge based on approved FERC filings. 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.

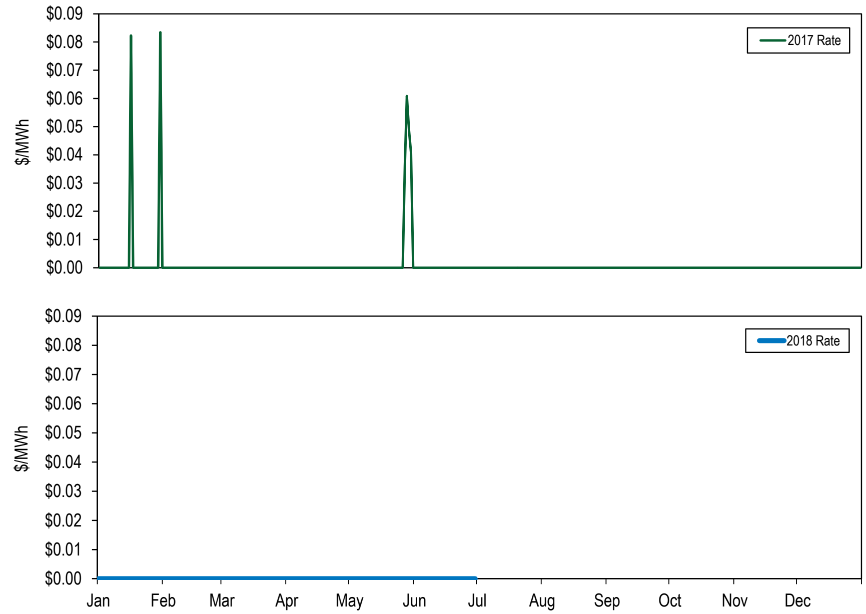
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-13 shows the reactive services rates associated with local voltage support in the first six months of 2017 and 2018. Table 4-13 shows that in the first six months of 2018 the ComEd Control Zone had the highest rate. Real-time load in the ComEd Control Zone paid an average of $0.112 per MWh for reactive services associated with local voltage support, $0.047 or 73.2 percent higher than the average rate paid in the first six months of 2017.

Table 4-13 Local voltage support rates: January through June, 2017 and 2018

Control Zone	(Jan - Jun) 2017 ($/MWh)	(Jan - Jun) 2018 ($/MWh)	Difference ($/MWh)
AECO	0.000	0.000	(0.000)
AEP	0.001	0.000	(0.001)
APS	0.004	0.000	(0.004)
ATSI	0.000	0.000	0.000
BGE	0.114	0.000	(0.114)
ComEd	0.065	0.112	0.047
DAY	0.000	0.000	0.000
DEOK	0.000	0.000	0.000
DLCO	0.000	0.000	0.000
Dominion	0.001	0.000	(0.001)
DPL	0.070	0.002	(0.067)
EKPC	0.000	0.021	0.021
JCPL	0.000	0.000	(0.000)
Met-Ed	0.002	0.000	(0.002)
PECO	0.004	0.000	(0.004)
PENELEC	0.197	0.004	(0.193)
Pepco	0.112	0.000	(0.112)
PPL	0.000	0.000	(0.000)
PSEG	0.000	0.000	(0.000)
RECO	0.000	0.000	(0.000)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2017 and the first six months in 2018. RTO wide reactive charges were incurred three times in 2017 and were not incurred in 2018.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): January 2017 through June, 2018



Balancing Operating Reserve Determinants

Table 4-14 shows the determinants used to allocate the regional balancing operating reserve charges in the first six months of 2017 and 2018. Total real-time load and real-time exports were 395,603 GWh, 2.7 percent higher in the first six months of 2018 compared to the first six months of 2017. Total deviations summed across the demand, supply, and generator categories were 36,156 GWh, 1.4 percent lower in the first six months of 2018 compared to the first six months of 2017.

Table 4-14 Balancing operating reserve determinants (GWh): January through June, 2017 and 2018

		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 - Jun) 2017	RTO	369,585	15,749	385,334	44,804	17,601	14,587	76,992
	East	174,303	5,444	179,747	22,087	10,267	7,063	39,416
	West	195,282	10,304	205,586	22,480	7,141	7,524	37,145
(Jan - Jun) 2018	RTO	383,847	11,756	395,603	43,311	14,891	17,700	75,902
	East	180,039	6,116	186,155	21,122	9,092	9,032	39,246
	West	203,808	5,639	209,448	21,782	5,706	8,668	36,156
Difference	RTO	14,262	(3,993)	10,269	(1,492)	(2,710)	3,113	(1,089)
	East	5,736	672	6,408	(965)	(1,174)	1,969	(170)
	West	8,526	(4,665)	3,861	(698)	(1,435)	1,144	(989)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-15 shows the different categories by the type of transactions that incurred deviations. In the first six months of 2018, 27.7 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 72.3 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-15 Deviations by transaction type: January through June, 2018

Deviation		Deviation (GWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	219	185	34	0.3%	0.5%	0.1%
	DECs Only	8,953	4,173	4,372	11.8%	10.6%	12.1%
	Exports Only	3,047	1,630	1,417	4.0%	4.2%	3.9%
	Load Only	28,830	14,231	14,599	38.0%	36.3%	40.4%
	Combination with DECs	1,178	545	633	1.6%	1.4%	1.7%
	Combination without DECs	1,084	356	727	1.4%	0.9%	2.0%
Supply	Bilateral Purchases Only	196	130	66	0.3%	0.3%	0.2%
	Imports Only	3,797	2,473	1,325	5.0%	6.3%	3.7%
	INCs Only	9,694	5,531	4,070	12.8%	14.1%	11.3%
	Combination with INCs	1,170	930	240	1.5%	2.4%	0.7%
	Combination without INCs	34	28	6	0.0%	0.1%	0.0%
Generators		17,700	9,032	8,668	23.3%	23.0%	24.0%
Total		75,902	39,246	36,156	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-16 shows the totals for each credit category in the first six months of 2017 and 2018. During the first six months of 2018, 73.5 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 9.9 percentage points from 63.6 in 2017.

Table 4-16 Energy uplift credits by category: January through June, 2017 and 2018

Category	Type	(Jan - Jun) 2017 Credits (Millions)	(Jan - Jun) 2018 Credits (Millions)	Change	Percent Change	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Day-Ahead	Generators	$8.6	$27.9	$19.4	226.0%	17.3%	19.1%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	2,831.4%	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Generators	$25.3	$65.3	$39.9	157.6%	51.1%	44.6%
	Imports	$0.0	$0.5	$0.5	93,468.7%	0.0%	0.3%
	Load Response	$0.2	$0.0	($0.2)	(95.8%)	0.4%	0.0%
	Local Constraints Control	$0.4	$0.0	($0.3)	(86.6%)	0.7%	0.0%
	Lost Opportunity Cost	$5.7	$41.9	$36.2	640.1%	11.4%	28.6%
Reactive Services	Day-Ahead	$8.7	$9.5	$0.8	9.1%	17.6%	6.5%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.1	$0.0	($0.1)	(89.0%)	0.2%	0.0%
	Reactive Services	$0.5	$0.7	$0.2	43.5%	0.9%	0.5%
	Synchronous Condensing	$0.0	$0.5	$0.5	1,604.6%	0.1%	0.3%
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)	(100.0%)	0.0%	0.0%
	Testing	$0.1	$0.0	($0.1)	(81.4%)	0.3%	0.0%
Total		$49.6	$146.4	$96.8	195.1%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-17 shows the distribution of total energy uplift credits by unit type in the first six months of 2017 and the first six months of 2018. All fossil fuel unit types received higher uplift payments in the first six months of 2018 compared to the first six months of 2017.

Table 4-17 Energy uplift credits by unit type: January through June, 2017 and 2018

Unit Type	(Jan - Jun) 2017 Credits (Millions)	(Jan - Jun) 2018 Credits (Millions)	Change	Percent Change	(Jan - Jun) 2017 Share	(Jan - Jun) 2018 Share
Combined Cycle	$4.3	$17.8	$13.5	310.5%	8.8%	12.2%
Combustion Turbine	$23.7	$68.7	$44.9	189.3%	48.0%	47.1%
Diesel	$0.3	$1.1	$0.8	249.7%	0.7%	0.8%
Hydro	$0.1	$0.0	($0.1)	(100.0%)	0.1%	0.0%
Nuclear	$0.1	$0.0	($0.1)	(86.2%)	0.1%	0.0%
Solar	$0.0	$0.0	$0.0	343.4%	0.0%	0.0%
Steam - Coal	$16.5	$34.9	$18.4	111.7%	33.3%	23.9%
Steam - Other	$2.5	$22.3	$19.7	774.2%	5.1%	15.3%
Wind	$1.9	$1.1	($0.8)	(42.6%)	3.9%	0.8%
Total	$49.5	$145.9	$96.4	194.9%	100.0%	100.0%

Table 4-18 shows the distribution of energy uplift credits by category and by unit type in the first six months of 2018. Coal fired steam turbines received 58.6 percent of the day-ahead generator credits in the first six months of 2018, 24.6 percentage points lower than the share received in the first six months of 2017. Combustion turbines received 56.0 percent of the balancing operating reserve generator credits in the first six months of 2018, 23.3 percentage points lower than the share received in the first six months of 2017. Combustion turbines received 71.7 percent of the lost opportunity cost credits in the first six months of 2018, 3.3 percentage points lower than the share received in the first six months of 2017.

Table 4-18 Energy uplift credits by unit type: January through June, 2018

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	9.3%	15.9%	0.0%	0.0%	11.5%	0.2%	0.0%	0.0%
Combustion Turbine	4.0%	56.0%	0.0%	0.0%	71.7%	8.9%	100.0%	100.0%
Diesel	0.0%	0.6%	0.0%	100.0%	1.3%	1.3%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	58.6%	6.1%	0.0%	0.0%	12.5%	86.8%	0.0%	0.0%
Steam - Others	28.1%	21.3%	0.0%	0.0%	0.4%	2.8%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%
Total (Millions)	$27.9	$65.3	$0.0	$0.0	$41.9	$10.7	$0.0	$0.0

Table 4-18 also shows the distribution of reactive service credits and black start services credits by unit type. In first six months of 2018, coal units received 86.8 of all reactive services credits.

Concentration of Energy Uplift Credits

There continues to be 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 the lack of transparency makes it almost impossible for competition to affect these payments.

Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 29.0 percent of total energy uplift credits in the first six months of 2018, compared to 32.9 percent in 2017. In the first six months of 2018, 267 units received 90 percent of all energy uplift credits, compared to 226 units in 2017.

Figure 4-6 Cumulative share of energy uplift credits: January through June, 2017 and 2018 by unit

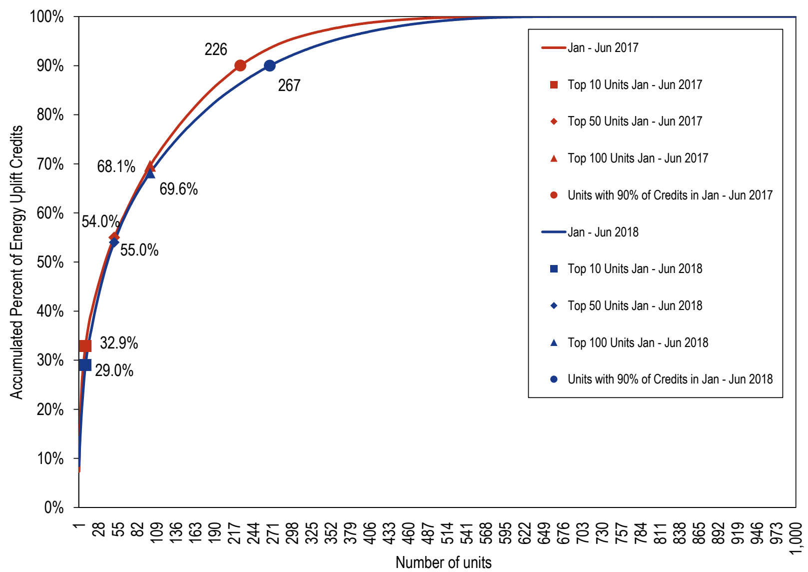


Table 4-19 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in the first six months of 2018.

Table 4-19 Top 10 units and organizations energy uplift credits: January through June, 2018

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$21.0	75.0%	$27.3	97.8%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$21.0	32.2%	$53.3	81.6%
	Local Constraints Control	$0.0	100.0%	$0.0	100.0%
	Lost Opportunity Cost	$8.3	19.8%	$31.7	75.6%
Reactive Services		$10.3	96.5%	$10.7	100.0%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.0	92.8%	$0.0	100.0%
Total		$42.3	29.0%	$113.8	78.0%

Table 4-20 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first six months of 2018, 44.7 percent of all credits paid to these units were allocated to deviations while the remaining 55.3 percent were paid for reliability reasons.

Table 4-20 Balancing operating reserve credits to top 10 units by category and region: January through June, 2018

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$10.9	$0.1	$0.7	$7.4	$0.0	$2.0	$21.0
Share	51.9%	0.3%	3.1%	35.2%	0.1%	9.4%	100.0%

In the first six months of 2018, concentration in all energy uplift credit categories was high.[9] [10] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-21 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 7990, for balancing operating reserve credits to generators was 3506, for lost opportunity cost credits was 4349 and for reactive services credits was 9658.

Table 4-21 Daily energy uplift credits HHI: January through June, 2018

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7990	2685	10000	100.0%	59.6%
	Imports	10000	10000	10000	100.0%	99.9%
	Load Response	9253	5586	10000	100.0%	72.4%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	3506	1002	9853	99.3%	31.2%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9997	9944	10000	100.0%	60.5%
	Lost Opportunity Cost	4349	932	10000	100.0%	23.7%
Reactive Services		9658	4203	10000	100.0%	88.6%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		10000	10000	10000	100.0%	43.0%
Total		3479	810	9339	96.6%	22.0%

9 See *2017 State of the Market Report for PJM*, Volume 2: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
10 Table 4-22 excludes local constraints control categories.

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 market clearing auction while self-scheduled units are committed by generation owners. Table 4-22 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[11] In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. 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 are noneconomic for the day or segment. [12]

Table 4-22 Dispatch status, commitment status and uplift eligibility

			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 4-23 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-23 shows that in the first six months of 2018, 37.7 percent of generation was pool-scheduled in the Day-Ahead Energy Market and 39.0 percent was pool-scheduled in the Real-Time Energy Market. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. This occurs because the majority of nuclear and coal resources, which make up 64.7 percent of real-time generation, are self-scheduled.

Table 4-23 Day-ahead and real-time generation by status and eligibility to set LMP (GWh): January through June, 2018

	Self Scheduled			Pool Scheduled						
	Dispatchable	Ecomin	Block Loaded	Dispatchable	Ecomin	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	49,942	95,495	106,486	64,791	75,704	11,782	404,199	152,277	251,922	114,732
Share of Day-Ahead	12.4%	23.6%	26.3%	16.0%	18.7%	2.9%	100.0%	37.7%	62.3%	28.4%
Real-Time Generation	42,137	72,586	131,385	61,714	82,304	13,638	403,765	157,656	246,108	103,851
Share of Real-Time	10.4%	18.0%	32.5%	15.3%	20.4%	3.4%	100.0%	39.0%	61.0%	25.7%

11 PJM has modified the basic rules of eligibility to set price in its CT price setting logic. Under CT price setting logic, the economic minimum of a block loaded CT is assumed to be lower than the actual offer. The result is that the CT may set price at its incremental energy offer for a MWh output level that it cannot produce, and thus at a price that does not represent actual marginal cost. The reduction appears to be at the discretion of the operators and does not appear to be applied to all CTs. The rules are not clearly stated in the PJM tariff or manuals. Not all CTs with a reduced economic minimum are marginal.

12 Noneconomic resources are those whose market revenues for the day or segment are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Economic and Noneconomic Generation[13]

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 or producing energy in real time at an incremental offer higher than the LMP and 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 4-24 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In the first six months of 2018, 85.7 percent of the day-ahead generation eligible for operating reserve credits was economic and 69.6 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 4-24 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-24 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through June, 2018

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	130,455	21,826	85.7%	14.3%
Real-Time	98,616	43,142	69.6%	30.4%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-25 shows the generation receiving day-ahead and balancing operating reserve credits. In the first six months of 2018, 3.3 percent of the day-ahead generation eligible for operating reserve credits received credits and 2.1 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-25 Generation receiving operating reserve credits (GWh): January through June, 2018

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	152,281	4,966	3.3%
Real-Time	141,757	2,956	2.1%

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 have otherwise not been committed in the day-ahead. 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 may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-26 shows the total day-ahead generation and the subset of that generation committed for reliability by PJM. In the first six months of 2018, 1.9 percent of the total day-ahead generation was committed for reliability by PJM, 0.8 percentage points higher than in the first six months of 2017.

13 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.

14 See PJM OA Schedule 1 § 3.2.3(b).

15 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 18, 2017) at 32, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

Table 4-26 Day-ahead generation committed for reliability (GWh): January 2017 through June 2018

	2017			2018		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,967	1,051	1.5%	78,368	1,209	1.5%
Feb	61,356	725	1.2%	63,095	780	1.2%
Mar	66,657	523	0.8%	67,699	1,712	2.5%
Apr	58,457	334	0.6%	58,457	967	1.7%
May	61,164	952	1.6%	61,164	1,799	2.9%
Jun	69,964	634	0.9%	69,964	1,188	1.7%
Jul	79,334	1,157	1.5%			
Aug	74,129	876	1.2%			
Sep	65,211	1,047	1.6%			
Oct	61,308	1,013	1.7%			
Nov	61,980	589	1.0%			
Dec	73,448	1,025	1.4%			
Total ((Jan - Jun))	389,565	4,219	1.1%	398,746	7,655	1.9%
Total	804,975	9,926	1.2%	398,746	7,655	1.9%

Pool-scheduled units 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. Pool-scheduled units committed for reliability by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market.

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 4-27 shows the total day-ahead generation committed for reliability by PJM by category. In the first six months of 2018, 47.0 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 36.8 percent paid as day-ahead operating reserve credits and 10.2 percent paid as reactive services. The remaining 53.0 percent of the day-ahead generation committed for reliability by PJM did not need to be made whole.

Table 4-27 Day-ahead generation committed for reliability by category (GWh): January through June, 2018

	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	0	227	983	1,209
Feb	0	561	218	780
Mar	83	701	928	1,712
Apr	170	163	634	967
May	273	632	893	1,799
Jun	256	532	400	1,188
Total (Jan - Jun)	782	2,817	4,056	7,655
Share	10.2%	36.8%	53.0%	100.0%

Total day-ahead operating reserve credits in the first six months of 2018 were $27.9 million, of which $24.2 million or 86.2 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services.

Geography of Charges and Credits

Table 4-28 shows the geography of charges and credits in the first six months of 2018. Table 4-28 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 ComEd Control Zone paid 10.1 percent of all operating reserve charges allocated regionally while resources in the ComEd Control Zone were paid 6.2 percent of the corresponding credits. The ComEd Control Zone received less operating reserve credits than operating reserve charges paid and had 11.5 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control

Zone paid 3.6 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 5.4 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 5.5 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 88.3 percent of all charges were allocated in control zones, 2.8 percent in hubs and aggregates and 8.8 percent in interfaces.

Table 4-28 Geography of regional charges and credits: January through June, 2018

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$1.8	$1.2	($0.5)	1.3%	0.9%	1.2%	0.0%
	AEP	$19.2	$16.8	($2.5)	14.2%	12.4%	5.4%	0.0%
	APS	$7.6	$2.1	($5.5)	5.6%	1.6%	11.9%	0.0%
	ATSI	$9.7	$9.5	($0.1)	7.1%	7.0%	0.3%	0.0%
	BGE	$4.8	$7.4	$2.5	3.6%	5.4%	0.0%	5.5%
	ComEd	$13.7	$8.4	($5.3)	10.1%	6.2%	11.5%	0.0%
	DAY	$2.5	$5.4	$2.9	1.8%	4.0%	0.0%	6.3%
	DEOK	$4.3	$1.7	($2.6)	3.2%	1.2%	5.7%	0.0%
	DLCO	$2.0	$0.6	($1.4)	1.5%	0.4%	3.1%	0.0%
	Dominion	$14.4	$32.9	$18.5	10.7%	24.3%	0.0%	40.3%
	DPL	$3.8	$7.5	$3.7	2.8%	5.5%	0.0%	8.0%
	EKPC	$1.9	$2.5	$0.6	1.4%	1.8%	0.0%	1.2%
	External	$0.0	$1.7	$1.7	0.0%	1.2%	0.0%	3.7%
	JCPL	$3.2	$1.1	($2.1)	2.3%	0.8%	4.5%	0.0%
	Met-Ed	$2.7	$0.9	($1.8)	2.0%	0.7%	3.8%	0.0%
	PECO	$6.0	$2.7	($3.3)	4.5%	2.0%	7.3%	0.0%
	PENELEC	$4.5	$4.4	($0.1)	3.3%	3.2%	0.1%	0.0%
	Pepco	$4.6	$18.7	$14.2	3.4%	13.8%	0.0%	30.8%
	PPL	$6.9	$2.0	($4.8)	5.1%	1.5%	10.5%	0.0%
	PSEG	$5.9	$7.7	$1.9	4.3%	5.7%	0.0%	4.0%
	RECO	$0.2	$0.0	($0.2)	0.2%	0.0%	0.5%	0.0%
	All Zones	$119.4	$135.1	$15.7	88.3%	99.6%	65.7%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.3	$0.0	($0.3)	0.3%	0.0%	0.7%	0.0%
	Dominion	$0.5	$0.0	($0.5)	0.4%	0.0%	1.2%	0.0%
	Eastern	$0.3	$0.0	($0.3)	0.2%	0.0%	0.6%	0.0%
	New Jersey	$0.3	$0.0	($0.3)	0.2%	0.0%	0.7%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Western Interface	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western	$2.2	$0.0	($2.2)	1.6%	0.0%	4.8%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$3.8	$0.0	($3.8)	2.8%	0.0%	8.3%	0.0%

Table 4-28 Geography of regional charges and credits: January through June, 2018 (continued)

Location		Charges (Millions)	Credits (Millions)	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Hudson	$0.1	$0.0	($0.1)	0.1%	0.0%	0.3%	0.0%
	IMO	$1.3	$0.0	($1.3)	1.0%	0.0%	2.9%	0.0%
	Linden	$0.3	$0.0	($0.3)	0.2%	0.0%	0.7%	0.0%
	MISO	$2.8	$0.0	($2.8)	2.1%	0.0%	6.1%	0.0%
	NCMPA Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Neptune	$0.4	$0.0	($0.4)	0.3%	0.0%	0.9%	0.0%
	NIPSCO	$0.1	$0.0	($0.1)	0.0%	0.0%	0.1%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	NYIS	$1.0	$0.0	($1.0)	0.7%	0.0%	2.1%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	South Exp	$2.2	$0.0	($2.2)	1.6%	0.0%	4.8%	0.0%
	South Imp	$3.4	$0.0	($3.4)	2.5%	0.0%	7.4%	0.0%
	All Interfaces	$12.0	$0.5	($11.5)	8.8%	0.4%	26.0%	0.0%
	Total	$135.2	$135.6	$0.4	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. They are paid under two different scenarios. The first scenario occurs if a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is 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 the desired output. For purposes of this report, this LOC will be referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine is schedule 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 the day-ahead financial position of the unit plus the balancing spot energy market position. For purposes of this report, this LOC will be referred to as day-ahead LOC.

Table 4-29 shows monthly day-ahead and real-time LOC credits in 2017 and the first six months of 2018. In the first six months of 2018, LOC credits increased by $36.2 million or 640.1 percent compared to 2017. The increase of $36.2 million is comprised of a $27.0 million increase in day-ahead LOC and a $9.3 million increase in real-time LOC. Table 4-30 shows for combustion turbines and diesels 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 six months of 2018, 20.0 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 9.0 percentage points higher than in 2017.

Table 4-29 Monthly lost opportunity cost credits (Millions): January 2017 through June 2018

	2017			2018		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.1	$0.3	$0.4	$13.7	$8.0	$21.7
Feb	$0.1	$0.1	$0.1	$0.1	$0.0	$0.2
Mar	$0.9	$0.2	$1.1	$3.2	$0.2	$3.4
Apr	$0.5	$0.3	$0.8	$2.5	$1.4	$3.9
May	$0.8	$1.0	$1.8	$6.7	$2.3	$9.1
Jun	$0.7	$0.8	$1.5	$3.7	$0.0	$3.7
Jul	$1.5	$0.2	$1.7			
Aug	$0.5	$0.1	$0.6			
Sep	$1.5	$0.5	$1.9			
Oct	$0.8	$0.2	$0.9			
Nov	$0.5	$0.3	$0.8			
Dec	$2.3	$0.6	$3.0			
Total (Jan - Jun)	$3.0	$2.6	$5.7	$30.0	$11.9	$41.9
Total	$10.1	$4.5	$14.6	$30.0	$11.9	$41.9
Share	69%	31%	100%	72%	28%	100%

Table 4-30 Day-ahead generation from combustion turbines and diesels (GWh): January 2017 through June 2018

	2017			2018		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	359	33	9	1,893	382	223
Feb	318	27	9	296	40	19
Mar	778	128	49	1,012	252	109
Apr	473	88	28	1,374	239	87
May	669	75	38	2,089	405	161
Jun	1,153	120	61	1,427	339	109
Jul	1,815	265	123			
Aug	1,341	121	51			
Sep	2,205	123	66			
Oct	1,850	138	65			
Nov	757	106	38			
Dec	898	213	110			
Total (Jan - Jun)	3,749	472	193	8,091	1,656	709
Total	12,616	1,438	646	8,091	1,656	709
Share	100%	11%	5%	100%	20%	9%

Intraday Segments Uplift Settlement

The use of intraday segments to calculate the need for uplift payments results in uplift payments to units that are profitable on a daily basis. The MMU recommends the elimination of intraday segments to calculate uplift payments and the return to calculating uplift based on the entire operating day. Table 4-31 displays balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. Balancing operating reserve credits would have been $8.5 million or 12.6 percent lower in 2017 if they were calculated on a daily basis. In the first six months of 2018, balancing operating reserve credits would have been $10.5 million or 16.3 percent lower if they were calculated on a daily basis.

Table 4-31 Intraday segments and daily balancing operating reserve credits: January 2017 through June 2018

	2017 BOR Credits (Millions)			2018 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$7.0	$6.7	($0.3)	$33.1	$28.0	($5.2)
Feb	$1.2	$1.1	($0.1)	$1.7	$1.3	($0.4)
Mar	$4.3	$3.7	($0.6)	$3.0	$2.4	($0.6)
Apr	$2.4	$1.9	($0.4)	$5.8	$4.3	($1.5)
May	$5.4	$4.6	($0.9)	$8.5	$6.6	($1.9)
Jun	$5.0	$4.5	($0.5)	$13.0	$12.1	($0.9)
Jul	$6.1	$4.8	($1.3)			
Aug	$4.7	$4.1	($0.6)			
Sep	$8.2	$6.8	($1.4)			
Oct	$7.0	$6.3	($0.7)			
Nov	$6.1	$5.5	($0.5)			
Dec	$9.7	$8.6	($1.0)			
Total ((Jan - Jun))	$25.3	$22.5	($2.8)	$65.3	$54.7	($10.5)
Total	$67.1	$58.6	($8.5)	$65.3	$54.7	($10.5)

For lost opportunity cost credits calculated under five minute settlements, each five minute interval is defined to be its own distinct segment. Prior to April 1, 2018, each hour was defined to be its own distinct segment. Table 4-32 displays day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2017, LOC credits would have been $1.8 million or 18.2 percent lower if they were calculated on a daily basis. In the first six months of 2018, LOC credits would have been $6.8 million or 22.7 percent lower if they were calculated on a daily basis.

Table 4-32 Intraday segments and daily lost opportunity cost credits: January 2017 through June 2018

	2017 Day Ahead LOC Credits (Millions)			2018 Day Ahead LOC Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$0.1	$0.1	($0.0)	$13.7	$11.0	($2.8)
Feb	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)
Mar	$0.9	$0.7	($0.2)	$3.2	$2.7	($0.5)
Apr	$0.5	$0.3	($0.1)	$2.5	$1.7	($0.8)
May	$0.8	$0.7	($0.1)	$6.7	$5.3	($1.4)
Jun	$0.7	$0.6	($0.1)	$3.7	$2.4	($1.3)
Jul	$1.5	$1.3	($0.2)			
Aug	$0.5	$0.4	($0.1)			
Sep	$1.5	$1.3	($0.2)			
Oct	$0.8	$0.6	($0.2)			
Nov	$0.5	$0.3	($0.2)			
Dec	$2.3	$1.9	($0.4)			
Total ((Jan - Jun))	$3.0	$2.5	($0.6)	$30.0	$23.2	($6.8)
Total	$10.1	$8.3	($1.8)	$30.0	$23.2	($6.8)