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 also 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. 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 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 decreased by $13.9 million, or 35.2 percent, in the first three months of 2017 compared to the first three months of 2016, from $39.5 million to $25.6 million.
- **Energy Uplift Charges Categories.** The decrease of $13.9 million in the first three months of 2017 is comprised of a $16.1 million decrease in day-ahead operating reserve charges, a $3.5 million decrease in balancing operating reserve charges and a $5.6 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.028 per MWh, a DEC paid $0.227 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.202 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.025 per MWh, real-time load paid $0.024 per MWh, a DEC paid $0.218 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.193 per MWh.
- **Reactive Services Rates.** The PENELEC, BGE and Pepco control zones had the three highest local voltage support rates: $0.232, $0.222 and $0.222 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 86.5 percent of all day-ahead generator credits. Combustion turbines received 75.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 44.7 percent of all credits. The top 10

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 costs 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.

© 2017 Monitoring Analytics, LLC

organizations received 83.3 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7331, balancing operating reserves HHI was 3764 and lost opportunity cost HHI was 5581.

- **Economic and Noneconomic Generation.** In the first three months of 2017, 85.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 80.1 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first three months of 2017, 1.2 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 60.1 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2017, 89.0 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, 4.4 percent by transactions at hubs and aggregates and 6.6 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 58.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 39.7 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 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 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 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.)

© 2017 Monitoring Analytics, LLC

- The MMU recommends four additional modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours 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 30 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. Stakeholder process.)
- 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. Stakeholder process.)
- 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 reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. 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. Stakeholder process.)
- 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. Stakeholder process.)
- 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). In addition, the MMU recommends that PJM allow and wind units 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 compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should 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.)

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 or black start charges.

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. 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

© 2017 Monitoring Analytics, LLC

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 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. Some 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 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.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an 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.

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 Balancing Operating Reserve for Deviations Balancing Local Constraint	Real-Time Load plus Real-Time Export Transactions Deviations Applicable Requesting Party	in RTO, Eastern or Western Region
Canceled Resources Lost Opportunity Cost (LOC) Real-Time Import Transactions	Balancing Operating Reserve Startup Cancellation Balancing Operating Reserve LOC 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

© 2017 Monitoring Analytics, LLC

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 Reactive Services Local Constraint	Zonal Real-Time Load 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

Energy Uplift Charges

Total energy uplift charges decreased by $13.9 million or 35.2 percent in the first three months of 2017 compared to the first three months of 2016. Table 4-3 shows total energy uplift charges in the first three months of 2016 and 2017.[4]

Table 4-3 Total energy uplift charges: January 1 through March 31, 2016 and 2017

	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change	Percent Change
Total Energy Uplift	$39.5	$25.6	($13.9)	(35.2%)
Energy Uplift as a Percent of Total PJM Billing	0.4%	0.3%	(0.2%)	(36.6%)

Table 4-4 compares energy uplift charges by category for the first three months of 2016 and 2017. The decrease of $13.9 million in the first three months of 2017 is comprised of a decrease of $16.1 million in day-ahead operating reserve charges and a decrease of $3.5 million in balancing operating reserve charges. These decreases were offset by an increase of $5.6 million in reactive services charges.

Table 4-4 Energy uplift charges by category: January 1 through March 31, 2016 and 2017

Category	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$21.3	$5.2	($16.1)	(75.4%)
Balancing Operating Reserves	$17.9	$14.4	($3.5)	(19.4%)
Reactive Services	$0.3	$5.9	$5.6	2,244.5%
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.1	$0.1	$0.0	1.2%
Total	$39.5	$25.6	($13.9)	(35.2%)

4 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 April 14, 2017.

Table 4-5 compares monthly energy uplift charges by category for 2016 and the first three months of 2017.

Table 4-5 Monthly energy uplift charges: January 1, 2016 through March 31, 2017

	2016 Charges (Millions)						2017 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	$7.4	$7.5	$0.0	$0.0	$0.0	$14.9	$2.6	$7.4	$1.25	$0.0	$0.0	$11.3
Feb	$7.6	$6.5	$0.0	$0.0	$0.0	$14.2	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6
Mar	$6.4	$3.9	$0.2	$0.0	$0.0	$10.5	$0.6	$5.7	$1.4	$0.0	$0.0	$7.6
Apr	$3.0	$4.8	$0.2	$0.0	$0.0	$8.0						
May	$2.8	$3.3	$0.1	$0.0	$0.0	$6.3						
Jun	$4.6	$5.3	$0.1	$0.0	$0.1	$10.1						
Jul	$3.6	$10.9	$0.1	$0.0	$0.0	$14.6						
Aug	$2.4	$11.5	$0.0	$0.0	$0.0	$13.9						
Sep	$2.9	$6.9	$0.1	$0.0	$0.0	$9.9						
Oct	$3.6	$8.7	$0.3	$0.0	$0.0	$12.6						
Nov	$5.7	$2.8	$1.0	$0.0	$0.1	$9.5						
Dec	$7.3	$4.5	$0.4	$0.0	$0.0	$12.2						
Total (Jan - Mar)	$21.3	$17.9	$0.3	$0.0	$0.1	$39.5	$5.2	$14.4	$5.9	$0.0	$0.1	$25.6
Share (Jan - Mar)	54.0%	45.3%	0.6%	0.0%	0.1%	100.0%	20.5%	56.3%	22.9%	0.0%	0.2%	100.0%
Total	$57.3	$76.5	$2.5	$0.0	$0.3	$136.6	$5.2	$14.4	$5.9	$0.0	$0.1	$25.6
Share	42.0%	56.0%	1.8%	0.0%	0.2%	100.0%	20.5%	56.3%	22.9%	0.0%	0.2%	100.0%

Table 4-6 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.[5] Day-ahead operating reserve charges decreased by $16.1 million or 75.4 percent in the first three months of 2017 compared to the first three months of 2016.

Table 4-6 Day-ahead operating reserve charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Day-Ahead Operating Reserve Charges	$21.3	$5.2	($16.1)	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$21.3	$5.2	($16.1)	100.0%	100.0%

5 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.

© 2017 Monitoring Analytics, LLC

Table 4-7 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 $3.5 million in the first three months of 2017 compared to the first three months of 2016.

Table 4-7 Balancing operating reserve charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Balancing Operating Reserve Reliability Charges	$5.0	$5.7	$0.6	28.2%	39.3%
Balancing Operating Reserve Deviation Charges	$12.8	$8.7	($4.1)	71.5%	60.5%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.1%
Balancing Local Constraint Charges	$0.1	$0.0	($0.0)	0.3%	0.1%
Total	$17.9	$14.4	($3.5)	100.0%	100.0%

Table 4-8 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 three months of 2017, 81.7 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, an increase of 19.8 percentage points compared to the share in the first three months of 2016.

Table 4-8 Balancing operating reserve deviation charges: January 1 through March 31, 2016 and 2017

Charge Attributable To	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Make Whole Payments to Generators and Imports	$7.9	$7.1	($0.8)	62.0%	81.7%
Energy Lost Opportunity Cost	$4.9	$1.6	($3.3)	37.9%	18.2%
Canceled Resources	$0.0	$0.0	($0.0)	0.1%	0.0%
Total	$12.8	$8.7	($4.1)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges increased by $5.6 million in the first three months of 2017 compared to the first three months of 2016. Black start services charges and synchronous condensing charges remained at $0.1 million.

Table 4-9 Additional energy uplift charges: January 1 through March 31, 2016 and 2017

Type	(Jan - Mar) 2016 Charges (Millions)	(Jan - Mar) 2017 Charges (Millions)	Change (Millions)	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Reactive Services Charges	$0.3	$5.9	$5.6	81.4%	99.0%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.1	$0.1	$0.0	18.6%	1.0%
Total	$0.3	$5.9	$5.6	100.0%	100.0%

© 2017 Monitoring Analytics, LLC

Table 4-10 and Table 4-11 show the amount and percent shares of regional balancing charges in the first three months of 2016 and 2017. 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 three months of 2017, regional balancing operating reserve charges decreased by $3.4 million compared to the first three months of 2016. Balancing operating reserve reliability charges increased by $0.6 million or 12.4 percent and balancing operating reserve deviation charges decreased by $4.1 million or 31.8 percent.

Table 4-10 Regional balancing charges allocation (Millions): January 1 through March 31, 2016

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$3.2	17.7%	$1.7	9.3%	$0.1	0.6%	$4.9	27.7%
	Real-Time Exports	$0.1	0.3%	$0.1	0.3%	$0.0	0.0%	$0.1	0.6%
	Total	$3.2	18.0%	$1.7	9.6%	$0.1	0.6%	$5.0	28.3%
Deviation Charges	Demand	$5.3	29.8%	$1.9	10.4%	$0.1	0.6%	$7.3	40.8%
	Supply	$2.0	11.1%	$0.5	2.6%	$0.0	0.2%	$2.5	14.0%
	Generator	$2.2	12.3%	$0.8	4.4%	$0.0	0.2%	$3.0	16.9%
	Total	$9.5	53.3%	$3.1	17.4%	$0.2	1.1%	$12.8	71.7%
Total Regional Balancing Charges		$12.7	71.3%	$4.8	27.0%	$0.3	1.7%	$17.8	100%

Table 4-11 Regional balancing charges allocation (Millions): January 1 through March 31, 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$5.0	34.7%	$0.4	3.1%	$0.0	0.3%	$5.5	38.1%
	Real-Time Exports	$0.2	1.2%	$0.0	0.1%	$0.0	0.0%	$0.2	1.3%
	Total	$5.2	35.8%	$0.5	3.2%	$0.0	0.3%	$5.7	39.4%
Deviation Charges	Demand	$4.6	32.3%	$0.1	1.0%	$0.0	0.0%	$4.8	33.3%
	Supply	$1.9	13.3%	$0.1	0.4%	$0.0	0.0%	$2.0	13.8%
	Generator	$1.9	13.2%	$0.0	0.3%	$0.0	0.0%	$2.0	13.6%
	Total	$8.5	58.9%	$0.2	1.7%	$0.0	0.1%	$8.7	60.6%
Total Regional Balancing Charges		$13.6	94.7%	$0.7	4.9%	$0.1	0.4%	$14.4	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.[6]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2016 and the first three months of 2017. The average rate in the first three months of 2017 was $0.026 per MWh, $0.077 per MWh lower than the average in the first three months of 2016. The highest rate in the first three months of 2017 occurred on February 12, when the rate reached $0.172 per MWh, $0.230 per MWh lower than the $0.402 per MWh reached in the first three months of 2016, on February 16. 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 2016 or in the first three months of 2017.

6 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.

© 2017 Monitoring Analytics, LLC

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): January 1, 2016 through March 31, 2017

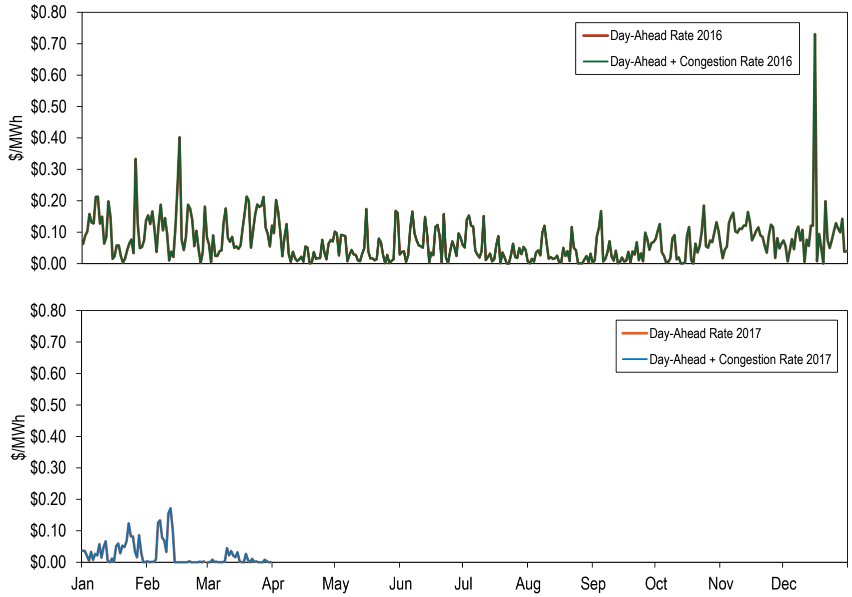


Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): January 1, 2016 through March 31, 2017

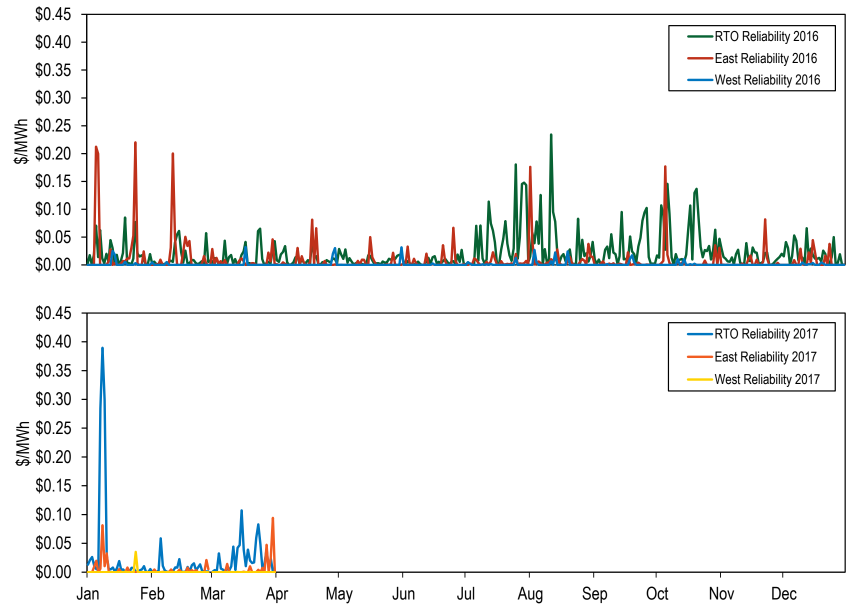


Figure 4-2 shows the RTO and the regional reliability rates for 2016 and the first three months of 2017. The average daily RTO reliability rate was $0.026 per MWh. The highest RTO reliability rate in the first three months of 2017 occurred on January 8, when the rate reached $0.390 per MWh, $0.304 per MWh higher than the $0.085 per MWh rate reached in the first three months of 2016, on January 19.

Figure 4-3 shows the RTO and regional deviation rates for 2016 and the first three months of 2017. The average daily RTO deviation rate was $0.180 per MWh. The highest daily rate in the first three months of 2017 occurred on January 9, when the RTO deviation rate reached $2.176 per MWh, $1.360 per MWh higher than the $0.816 per MWh rate reached in the first there months of 2016, on January 19.

© 2017 Monitoring Analytics, LLC

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): January 1, 2016 through March 31, 2017

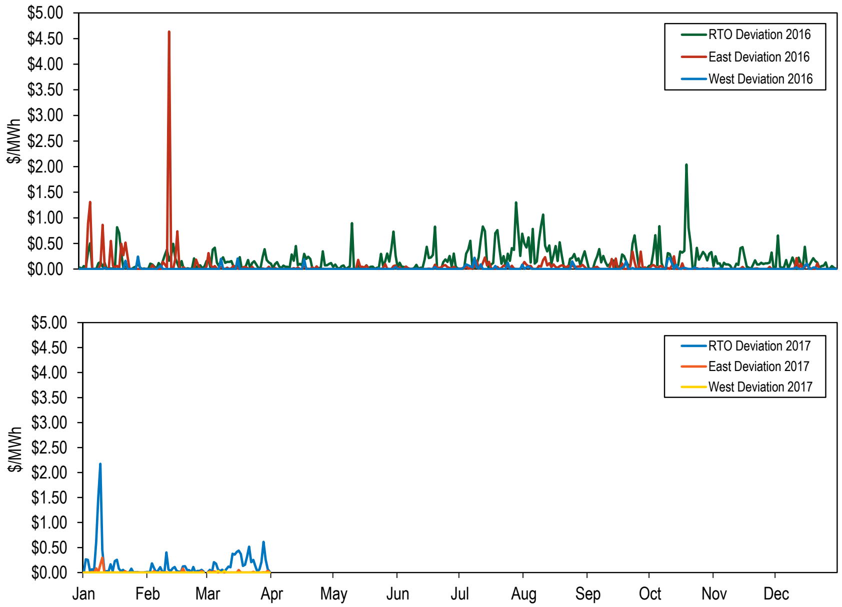


Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): January 1, 2016 through March 31, 2017

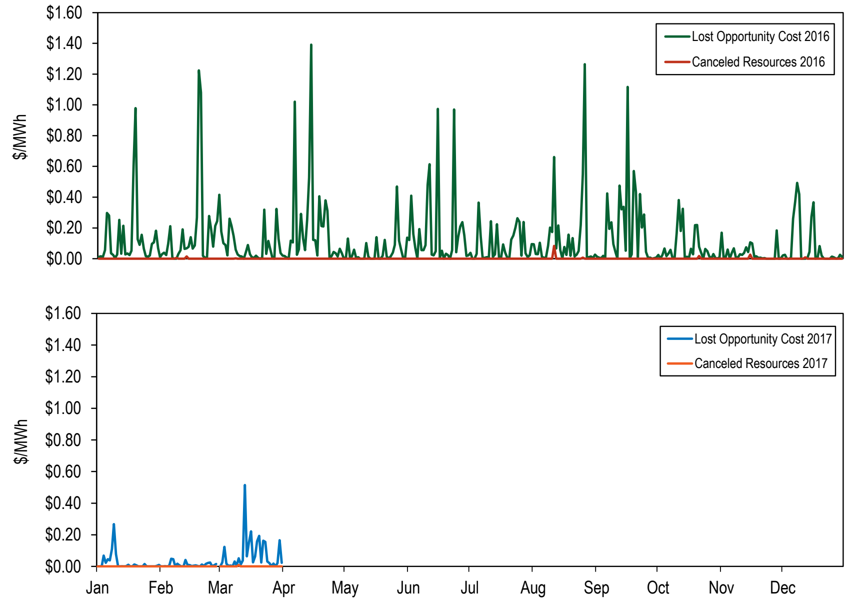


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2016 and the first three months of 2017. The lost opportunity cost rate averaged $0.042 per MWh. The highest lost opportunity cost rate occurred on March 12, when it reached $0.515 per MWh, $0.710 per MWh lower than the $1.225 per MWh rate reached in the first three months of 2016, on February 19.

Table 4-12 shows the average rates for each region in each category in the first three months of 2016 and 2017.

© 2017 Monitoring Analytics, LLC

Table 4-12 Operating reserve rates ($/MWh): January 1 through March 31, 2016 and 2017

Rate	(Jan - Mar) 2016 ($/MWh)	(Jan - Mar) 2017 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.103	0.026	(0.077)	(75.2%)
Day-Ahead with Unallocated Congestion	0.103	0.026	(0.077)	(75.2%)
RTO Reliability	0.016	0.026	0.010	62.8%
East Reliability	0.018	0.005	(0.013)	(72.4%)
West Reliability	0.001	0.000	(0.001)	(63.1%)
RTO Deviation	0.125	0.180	0.056	44.7%
East Deviation	0.156	0.012	(0.144)	(92.1%)
West Deviation	0.011	0.001	(0.011)	(93.9%)
Lost Opportunity Cost	0.130	0.042	(0.089)	(68.1%)
Canceled Resources	0.000	0.000	(0.000)	(58.8%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first three months of 2017. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.227 per MWh with a maximum rate of $2.663 per MWh, a minimum rate of $0.002 per MWh and a standard deviation of $0.356 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation charges. Table 4-13 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 4-13 Operating reserve rates statistics ($/MWh): January 1 through March 31, 2017

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	2.606	0.202	0.000	0.355
	DEC	2.663	0.227	0.002	0.356
	DA Load	0.172	0.025	0.000	0.038
	RT Load	0.471	0.028	0.000	0.067
	Deviation	2.606	0.202	0.000	0.355
West	INC	2.443	0.193	0.000	0.336
	DEC	2.500	0.218	0.002	0.338
	DA Load	0.172	0.025	0.000	0.038
	RT Load	0.390	0.024	0.000	0.059
	Deviation	2.443	0.193	0.000	0.336

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 4-14 shows the reactive services rates associated with local voltage support in the first three months of 2016 and 2017. Table 4-14 shows that in the first three months of 2017 the PENELEC Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.232 per MWh for reactive services associated with local voltage support, $0.229 or 9,659 percent higher than the average rate paid in the first three months of 2016.

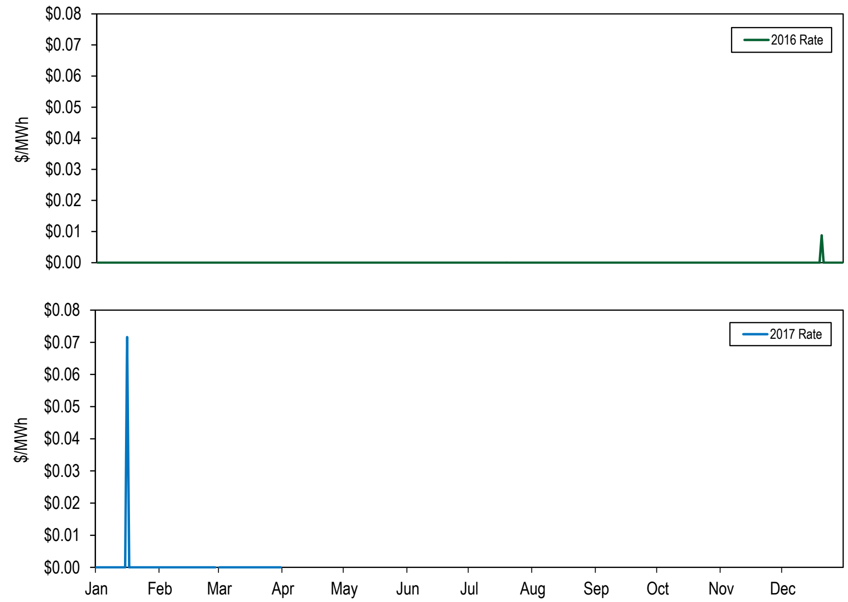
© 2017 Monitoring Analytics, LLC

Table 4-14 Local voltage support rates: January 1 through March 31, 2016 and 2017

Control Zone	(Jan - Mar) 2016 ($/MWh)	(Jan - Mar) 2017 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	0.000	NA
AEP	0.000	0.001	0.001	192.9%
AP	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.222	0.222	NA
ComEd	0.000	0.050	0.050	106,825.8%
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.000	0.000	NA
DPL	0.049	0.014	(0.035)	(71.1%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.000	0.000	0.000	NA
Met-Ed	0.000	0.002	0.002	NA
PECO	0.000	0.000	0.000	NA
PENELEC	0.002	0.232	0.229	9,659.0%
Pepco	0.000	0.222	0.222	NA
PPL	0.000	0.000	0.000	NA
PSEG	0.000	0.000	0.000	NA
RECO	0.000	0.000	0.000	NA

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2016 and the first three months of 2017. RTO wide reactive charges were incurred only once in 2016 (December) and once in the first three months of 2017 (January). Those are the only instances in which PJM scheduled resources to provide reactive support to reactive interfaces and the resources required make whole payments.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2016 and 2017



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in the first three months of 2016 and 2017. Total real-time load and real-time exports were 4,364,577 MWh or 2.2 percent lower in the first three months of 2017 compared to the first three months of 2016. Total deviations summed across the demand, supply, and generator categories were 596,228 MWh or 1.6 percent higher in the first three months of 2017 compared to the first three months of 2016.

© 2017 Monitoring Analytics, LLC

Table 4-15 Balancing operating reserve determinants (MWh): January 1 through March 31, 2016 and 2017

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
(Jan - Mar) 2016	RTO	196,811,940	3,636,742	200,448,682	21,016,147	7,818,373	8,749,562	37,584,082
	East	92,212,662	2,393,889	94,606,551	10,735,953	4,268,586	5,033,123	20,037,663
	West	104,599,278	1,242,853	105,842,131	10,128,601	3,477,800	3,716,439	17,322,839
(Jan - Mar) 2017	RTO	189,125,027	6,959,078	196,084,105	21,397,923	9,527,913	7,254,475	38,180,311
	East	88,981,325	3,199,115	92,180,440	10,691,631	5,532,319	3,348,509	19,572,459
	West	100,143,702	3,759,963	103,903,665	10,608,325	3,877,189	3,905,967	18,391,480
Difference	RTO	(7,686,913)	3,322,336	(4,364,577)	381,776	1,709,539	(1,495,087)	596,228
	East	(3,231,336)	805,226	(2,426,111)	(44,322)	1,263,733	(1,684,615)	(465,204)
	West	(4,455,576)	2,517,110	(1,938,466)	479,724	399,389	189,528	1,068,641

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first three months of 2017, 35.1 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 64.9 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 4-16 Deviations by transaction type: January 1 through March 31, 2017

Deviation		Deviation (MWh)			Share		
Category	Transaction	RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	232,750	189,935	42,815	0.6%	1.0%	0.2%
	DECs Only	4,302,256	1,877,138	2,327,151	11.3%	9.6%	12.7%
	Exports Only	1,353,888	607,012	746,876	3.5%	3.1%	4.1%
	Load Only	14,370,735	7,308,154	7,062,581	37.6%	37.3%	38.4%
	Combination with DECs	886,077	529,804	356,273	2.3%	2.7%	1.9%
	Combination without DECs	252,217	179,589	72,628	0.7%	0.9%	0.4%
Supply	Bilateral Purchases Only	139,718	96,885	42,833	0.4%	0.5%	0.2%
	Imports Only	1,174,118	898,717	275,401	3.1%	4.6%	1.5%
	INCs Only	6,894,515	3,756,326	3,019,785	18.1%	19.2%	16.4%
	Combination with INCs	1,301,185	765,088	536,097	3.4%	3.9%	2.9%
	Combination without INCs	18,376	15,303	3,073	0.0%	0.1%	0.0%
Generators		7,254,475	3,348,509	3,905,967	19.0%	17.1%	21.2%
Total		38,180,311	19,572,459	18,391,480	100.0%	100.0%	100.0%

© 2017 Monitoring Analytics, LLC

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in the first three months of 2016 and 2017. During the first three months of 2017, 55.9 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 10.7 percentage points from 45.1 in the first three months of 2016.

Table 4-17 Energy uplift credits by category: January 1 through March 31, 2016 and 2017

Category	Type	(Jan - Mar) 2016 Credits (Millions)	(Jan - Mar) 2017 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Day-Ahead	Generators	$21.3	$5.2	($16.1)	(75.4%)	54.1%	20.3%
	Imports	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Load Response	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(57.7%)	0.0%	0.0%
	Generators	$13.0	$12.8	($0.1)	(1.0%)	32.8%	49.6%
	Imports	$0.0	$0.0	($0.0)	(99.6%)	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	11.1%	0.0%	0.0%
	Local Constraints Control	$0.1	$0.0	($0.0)	(63.3%)	0.1%	0.1%
	Lost Opportunity Cost	$4.8	$1.6	($3.2)	(66.7%)	12.1%	6.2%
Reactive Services	Day-Ahead	$0.0	$6.0	$6.0	NA	0.0%	23.2%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	$0.0	63.0%	0.0%	0.1%
	Reactive Services	$0.2	$0.1	($0.2)	(67.5%)	0.6%	0.3%
	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Testing	$0.1	$0.1	$0.0	1.2%	0.1%	0.2%
Total		$39.4	$25.8	($13.6)	(34.5%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first three months of 2016 and 2017. The decrease in energy uplift in the first three months of 2017 compared to the first three months of 2016 was primarily a result of lower credits paid to coal fired steam turbines. Credits to these units decreased by $9.1 million or 45.1 percent.

© 2017 Monitoring Analytics, LLC

Table 4-18 Energy uplift credits by unit type: January 1 through March 31, 2016 and 2017

Unit Type	(Jan - Mar) 2016 Credits (Millions)	(Jan - Mar) 2017 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2016 Share	(Jan - Mar) 2017 Share
Combined Cycle	$6.6	$2.6	($4.0)	(60.8%)	16.7%	10.0%
Combustion Turbine	$11.6	$10.9	($0.7)	(6.0%)	29.3%	42.1%
Diesel	$0.2	$0.1	($0.0)	(24.4%)	0.5%	0.6%
Hydro	$0.0	$0.0	$0.0	60.7%	0.0%	0.0%
Nuclear	$0.1	$0.0	($0.1)	(100.0%)	0.3%	0.0%
Solar	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Steam - Coal	$19.8	$10.7	($9.1)	(46.1%)	50.3%	41.4%
Steam - Other	$0.9	$1.2	$0.3	34.7%	2.2%	4.5%
Wind	$0.3	$0.4	$0.1	38.5%	0.7%	1.4%
Total	$39.4	$25.8	($13.6)	(34.5%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first three months of 2017. Coal fired steam turbines received 86.5 percent of the day-ahead generator credits in the first three months of 2017, 6.9 percentage points higher than the share received in the first three months of 2016. Combustion turbines received 75.6 percent of the balancing generator credits in the first three months of 2017, 24.5 percentage points higher than the share received in the first three months of 2016. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits in the first three months of 2017, 20.6 percentage points lower than the share received in the first three months of 2016.

Table 4-19 Energy uplift credits by unit type: January 1 through March 31, 2017

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	10.4%	14.2%	0.0%	0.0%	10.0%	0.7%	0.0%	9.3%
Combustion Turbine	0.5%	75.6%	0.0%	99.3%	64.3%	1.0%	0.0%	90.7%
Diesel	0.1%	0.5%	0.0%	0.0%	3.9%	0.3%	0.0%	0.0%
Hydro	0.0%	0.0%	100.0%	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	86.5%	9.0%	0.0%	0.7%	2.6%	81.5%	0.0%	0.0%
Steam - Others	2.5%	0.2%	0.0%	0.0%	0.3%	16.6%	0.0%	0.0%
Wind	0.0%	0.5%	0.0%	0.0%	19.0%	0.0%	0.0%	0.0%
Total (Millions)	$5.2	$12.8	$0.0	$0.0	$1.6	$6.1	$0.0	$0.1

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In the first three months of 2017, coal units received 81.5 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 44.7 percent of total energy uplift credits in the first three months of 2017, compared to 53.4 percent in the first three months of 2016. In the first three months of 2017, 170 units received 90 percent of all energy uplift credits, compared to 140 units in the first three months of 2016.

Figure 4-6 Cumulative share of energy uplift credits: January 1 through March 31, 2016 and 2017, by unit

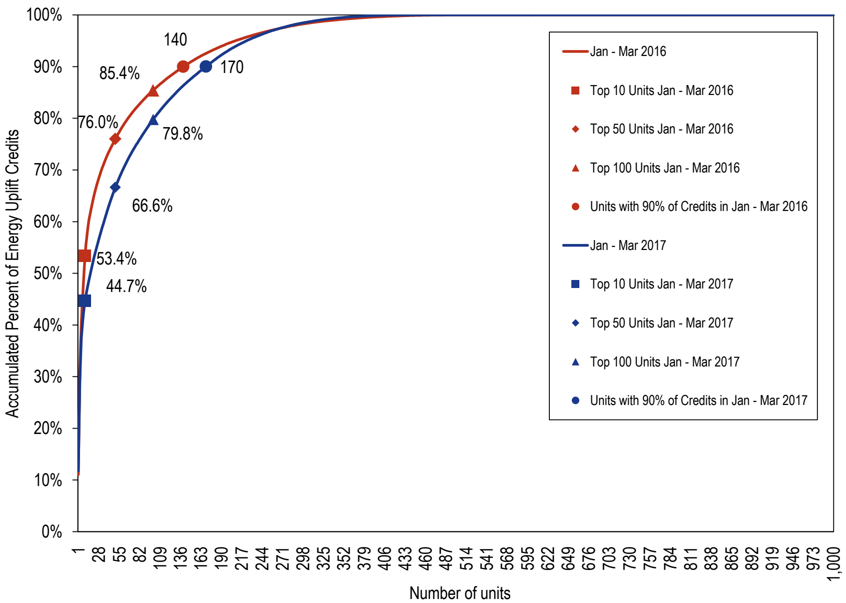


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January 1 through March 31, 2017

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$4.6	86.9%	$5.2	98.5%
Balancing	Canceled Resources	$0.0	100.0%	$0.0	100.0%
	Generators	$2.4	18.7%	$9.8	76.4%
	Local Constraints Control	$0.0	100.0%	$0.0	100.0%
	Lost Opportunity Cost	$0.4	28.2%	$1.1	69.4%
Reactive Services		$5.9	96.5%	$6.1	100.0%
Synchronous Condensing		$0.0	0.0%	$0.0	0.0%
Black Start Services		$0.1	93.4%	$0.1	100.0%
Total		$11.5	44.7%	$21.5	83.3%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2017, 66.1 percent of all credits paid to these units were allocated to deviations while the remaining 33.9 percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: January 1 through March 31, 2017

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$0.7	$0.1	$0.0	$1.5	$0.1	$0.0	$2.4
Share	31.5%	2.4%	0.0%	61.1%	5.0%	0.0%	100.0%

In the first three months of 2017, concentration in all energy uplift credit categories was high.[7] [8] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-22 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 7331, for balancing operating reserve credits to generators was 3764, for lost opportunity cost credits was 5581 and for reactive services credits was 8873.

7 See *2016 State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
8 Table 4-22 excludes local constraints control categories.

© 2017 Monitoring Analytics, LLC

Table 4-22 Daily energy uplift credits HHI: January 1 through March 31, 2017

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	7331	2229	10000	100.0%	44.4%
	Imports	NA	NA	NA	NA	NA
	Load Response	NA	NA	NA	NA	NA
Balancing	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	3764	1155	10000	100.0%	23.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9937	8935	10000	100.0%	97.2%
	Lost Opportunity Cost	5581	1481	10000	100.0%	14.8%
Reactive Services		8873	3866	10000	100.0%	57.0%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		9849	7585	10000	100.0%	51.8%
Total		3943	904	9903	99.5%	24.1%

Economic and Noneconomic Generation[9]

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 at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator 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. Table 4-23 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. 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 instructions are eligible for balancing operating reserve credits.

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 cost 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 costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first three months of 2017, 34.5 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.6 percent of the real-time generation was eligible for balancing operating reserve credits.[10]

Table 4-23 Day-ahead and real-time generation (GWh): January 1 through March 31, 2017

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	199,981	68,943	34.5%
Real-Time	199,798	65,083	32.6%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first three months of 2017, 85.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 80.1 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 generation was economic.

9 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.

10 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 operate as requested by PJM are eligible for balancing operating reserve credits.

© 2017 Monitoring Analytics, LLC

Table 4-24 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January 1 through March 31, 2017

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	58,931	10,012	85.5%	14.5%
Real-Time	52,152	12,931	80.1%	19.9%

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 three months of 2017, 2.9 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.8 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-25 Day-ahead and real-time generation receiving operating reserve credits (GWh): January 1 through March 31, 2017

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	68,943	2,019	2.9%
Real-Time	65,083	1,145	1.8%

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. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection (ALR) units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[11] 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.[12] Units scheduled as must run 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 scheduled as must run by PJM. In the first three months of 2017, 1.2 percent of the total day-ahead generation was scheduled as must run by PJM, 0.3 percentage points lower than the first three months of 2016.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): January 1, 2016 through March 31, 2017

	2016			2017		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	73,821	935	1.3%	71,967	1,071	1.5%
Feb	66,367	979	1.5%	61,356	725	1.2%
Mar	60,431	1,047	1.7%	66,657	523	0.8%
Apr	56,338	514	0.9%			
May	59,078	429	0.7%			
Jun	70,573	772	1.1%			
Jul	81,801	981	1.2%			
Aug	83,021	1,694	2.0%			
Sep	69,962	1,682	2.4%			
Oct	60,950	1,066	1.7%			
Nov	59,983	819	1.4%			
Dec	72,478	1,112	1.5%			
Total (Jan - Mar)	200,618	2,961	1.5%	199,981	2,318	1.2%
Total	814,803	12,031	1.5%	199,981	2,318	1.2%

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 scheduled as must run 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.

11 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-minutes.ashx>.

12 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version April 29, 2016) p. 32, <http://www.pjm.com/~/media/etools/emkt/markets-gateway-user-guide.ashx>.

© 2017 Monitoring Analytics, LLC

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 scheduled as must run by PJM by category. In the first three months of 2017, 60.1 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, 18.5 percent paid day-ahead operating reserve credits and 41.6 percent paid as reactive services. The remaining 39.9 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-27 Day-ahead generation scheduled as must run by PJM by category (GWh): January 1 through March 31, 2017

	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	338	256	477	1,071
Feb	411	172	141	725
Mar	215	2	306	523
Total (Jan - Mar)	964	430	925	2,318
Share	41.6%	18.5%	39.9%	100.0%

Total day-ahead operating reserve credits in the first three months of 2017 were $5.2 million, of which $4.0 million or 77.1 percent was paid to units scheduled as must run 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 three months of 2017. 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 AEP Control Zone paid 14.4 percent of all operating reserve charges allocated regionally, and resources in the AEP Control Zone were paid 10.2 percent of the corresponding credits. The AEP Control Zone received less operating reserve credits than operating reserve charges paid and had 10.7 percent of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the BGE Control Zone paid 4.3 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 17.4 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 33.7 percent of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-28 also shows that 89.0 percent of all charges were allocated in control zones, 4.4 percent in hubs and aggregates and 6.6 percent in interfaces.

© 2017 Monitoring Analytics, LLC

Table 4-28 Geography of regional charges and credits: January 1 through March 31, 2017

Location		Charges (Millions)	Credits (Millions)	Balance	Shares Total Charges	Shares Total Credits	Shares Deficit	Shares Surplus
Zones	AECO	$0.2	$0.2	($0.0)	1.1%	1.1%	0.0%	0.0%
	AEP	$2.8	$2.0	($0.8)	14.4%	10.2%	10.7%	0.0%
	AP	$1.1	$0.2	($0.9)	5.8%	1.1%	12.1%	0.0%
	ATSI	$1.4	$0.3	($1.1)	7.0%	1.4%	14.5%	0.0%
	BGE	$0.8	$3.4	$2.6	4.3%	17.4%	0.0%	33.7%
	ComEd	$1.9	$2.1	$0.2	9.9%	10.7%	0.0%	2.0%
	DAY	$0.4	$0.5	$0.1	1.8%	2.3%	0.0%	1.2%
	DEOK	$0.5	$0.4	($0.1)	2.8%	2.1%	1.6%	0.0%
	DLCO	$0.3	$0.0	($0.2)	1.3%	0.1%	3.0%	0.0%
	Dominion	$2.0	$4.1	$2.2	10.1%	21.0%	0.0%	28.2%
	DPL	$0.5	$0.5	$0.0	2.6%	2.7%	0.0%	0.4%
	EKPC	$0.3	$0.6	$0.3	1.8%	3.1%	0.0%	3.5%
	External	$0.0	$0.2	$0.2	0.0%	1.2%	0.0%	3.1%
	JCPL	$0.5	$0.3	($0.2)	2.4%	1.4%	2.5%	0.0%
	Met-Ed	$0.4	$0.0	($0.4)	2.0%	0.2%	4.7%	0.0%
	PECO	$0.9	$0.3	($0.6)	4.6%	1.4%	8.1%	0.0%
	PENELEC	$0.7	$0.3	($0.4)	3.5%	1.6%	4.9%	0.0%
	Pepco	$0.7	$2.5	$1.7	3.7%	12.5%	0.0%	22.5%
	PPL	$1.0	$0.3	($0.7)	5.3%	1.7%	9.3%	0.0%
	PSEG	$0.9	$1.3	$0.4	4.6%	6.7%	0.0%	5.5%
	RECO	$0.0	$0.0	($0.0)	0.2%	0.0%	0.6%	0.0%
	All Zones	$17.5	$19.7	$2.2	89.0%	100.0%	71.8%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.1	$0.0	($0.1)	0.6%	0.0%	1.5%	0.0%
	Dominion	$0.0	$0.0	($0.0)	0.2%	0.0%	0.6%	0.0%
	Eastern	$0.0	$0.0	($0.0)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$0.0	$0.0	($0.0)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	Western	$0.6	$0.0	($0.6)	3.2%	0.0%	8.1%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$0.9	$0.0	($0.9)	4.4%	0.0%	11.4%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.6%	0.0%	1.5%	0.0%
	Linden	$0.1	$0.0	($0.1)	0.3%	0.0%	0.7%	0.0%
	MISO	$0.4	$0.0	($0.4)	1.8%	0.0%	4.7%	0.0%
	Neptune	$0.1	$0.0	($0.1)	0.4%	0.0%	1.0%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Northwest	$0.0	$0.0	($0.0)	0.1%	0.0%	0.2%	0.0%
	NYIS	$0.2	$0.0	($0.2)	0.9%	0.0%	2.4%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	South Exp	$0.1	$0.0	($0.1)	0.6%	0.0%	1.6%	0.0%
	South Imp	$0.4	$0.0	($0.4)	1.8%	0.0%	4.6%	0.0%
	All Interfaces	$1.3	$0.0	($1.3)	6.6%	0.0%	16.8%	0.0%
	Total	$19.7	$19.7	$0.0	100.0%	100.0%	100.0%	100.0%

© 2017 Monitoring Analytics, LLC