



A Review of the October 2019 Performance Assessment Event

Operating Committee

Nov. 8, 2019

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Executive Summary

In early October, generators, transmission operators and load management resources successfully worked with PJM operators to maintain reliability during a short, abnormal October heat wave that led to emergency procedures, a Performance Assessment Interval and the first call on demand response resources in more than five years. This report details the conditions leading to these events, the actions PJM took, the decision-making behind those actions, conclusions and next steps.

PJM operators used the tools available to them to help ensure reliability and the delivery of bulk electricity to customers in the region without interruption. In general, these tools worked as designed, and prices largely reflected the tight system conditions resulting from extremely warm weather during a time when generation and transmission resources normally are out of service for maintenance. The most striking anomaly was load levels in the AEP and Mid-Atlantic zones that came in significantly below forecast. PJM has been and will continue to analyze this issue as well as pricing and operational issues that revealed themselves during this event.

PJM recognizes and appreciates the significant dedication of personnel throughout the PJM membership that ensured the reliable provision of service to wholesale customers during this period.

In Short: Events of Oct. 1 and Oct. 2

October is part of the fall shoulder season, when critical planned maintenance activities take generators out of service, significantly lowering the available generating capacity in the PJM footprint. Temperatures and load tend to be mild during this time. On Oct. 1, hot weather across much of PJM's footprint resulted in peak demand that exceeded the load forecast by about 5,500 MW, peaking at more than 125,500 MW. Peak demand at this time of year is typically closer to 100,000 MW.

As demand ramped up, PJM took several actions, including calling on spinning reserves for about 15 minutes, initiating a Shared Reserves event and importing an estimated 800 MW of power from a neighboring system. The rising demand also triggered three intervals of shortage pricing.

On the evening of Oct. 1, to meet the Day-Ahead Scheduling Reserve for Oct. 2, PJM called a Maximum Generation Emergency/Load Management Alert, an early alert that system conditions may require the use of the PJM emergency procedures. PJM also revised the load forecast for Oct. 2 to a peak of more than 132,000 MW as temperatures were forecast to be even higher in most of the PJM footprint.

Complicating the matter, on the morning of Oct. 2, a 765 kV transmission line was automatically taken out of service to isolate failed equipment, which heightened concerns about PJM's load/capacity position for the peak. And later in the morning, PJM was notified that as much as 2,000 MW of generation that was expected to be online would not be available for the peak of the day.

At noon on Oct. 2, PJM issued a two-hour lead time Pre-Emergency Load Management Reduction Action in the Dominion, PEPCO, Baltimore Gas & Electric (BGE) and AEP zones to address capacity concerns and to manage transmission constraints through the peak. This action triggered a Performance Assessment Interval (PAI), in which

capacity resources in the affected zones are required to perform – PJM's first since the program was implemented that affected generation resources.

It was also the first time demand response was called on in more than five years, triggered by the Pre-Emergency Load Reduction Action. Early analysis shows an estimated 725 MW of demand response was initiated in response to the call. PJM will release final demand response numbers as soon as they are available.

Contrary to expectations, the Oct. 2 actual peak only reached 126,500 MW, significantly lower than the projected 132,000 MW forecast. PJM is working to understand the difference between the forecast and the actual peak. Those efforts are described later in this paper, as is a detailed account of the conditions, actions and decision-making behind the actions of Oct. 1 and 2.

What are Performance Assessment Intervals?

Purpose Behind Capacity Performance

The Polar Vortex of 2014 made it clear to PJM Interconnection that stronger incentives were needed to encourage investment to ensure better generation performance year-round. During that event, on the coldest day of the year, 22 percent of the generation in PJM was unexpectedly unavailable to serve customers. That event demonstrated that resources of all types could be vulnerable to extreme conditions and that years of relatively mild weather may have led to less focus on generator maintenance.

In response to changing grid conditions and generator performance, on June 1, 2016, PJM implemented Capacity Performance rules to ensure that capacity resources are available whenever they are needed and to transition unit performance risk from load to generation, especially in extreme weather conditions. These rules are intended specifically to encourage resources to make needed upgrades in plant equipment, weatherization measures, fuel procurement arrangements, fuel supply infrastructure and other factors.

How Capacity Performance Works

Under Capacity Performance, resources must meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies. As a pay-for-performance requirement, resources may receive higher capacity payments and, in return, are expected to invest in modernizing equipment, firming up fuel supplies and adapting to use different fuels. Capacity Performance also incentivizes investment in new resources that are very reliable, available to meet demand during peak system conditions and therefore help to reduce costs in the energy markets. Resources with Capacity Performance commitments that fail to perform during power system emergencies are subject to significant non-performance charges.

PJM took a phased approach to implementing Capacity Performance. The number of megawatts cleared in the Reliability Pricing Model (RPM) capacity market as Capacity Performance increases each year until the delivery year 2020/2021, when all PJM resources are required to meet Capacity Performance requirements. For the 2019/2020 delivery year, approximately 84 percent of resources are required to meet Capacity Performance requirements.

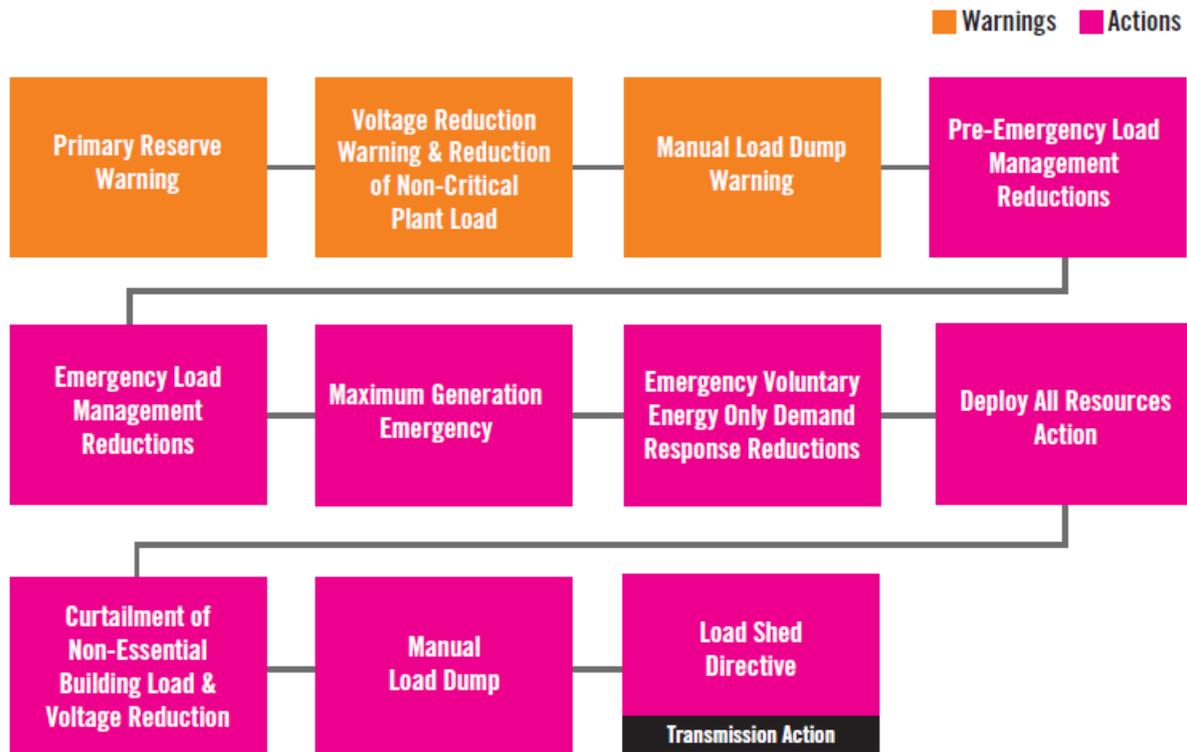
Performance Assessment Intervals

A PAI is an increment of time during which Capacity Performance resources are held to the Capacity Performance standard of deliverability. Resources subject to appraisal during PAIs are those that are located in the area where the PAI was triggered and cleared in the capacity auction with a Capacity Performance requirement. Resources that do not meet their Capacity Performance obligations during PAIs are subject to significant financial penalties.

PAIs occur for the duration of certain emergency actions declared by PJM. Emergency procedures are issued to mitigate capacity and transmission emergencies as detailed in Manual 13 and can include, but are not limited to, voltage reduction warnings, voltage reduction actions, manual load dump warnings or manual load dump actions.

PAIs are triggered for each interval in which PJM declares an Emergency Action (Figure 1). Emergency Warnings and Actions do not need to occur sequentially.

Figure 1. PJM Emergency Warnings and Actions



Non-performance is assessed based on the response of resources to fulfill their capacity commitments during a PAI. The shortfall/excess is calculated separately for each resource and each PAI. Resources with a shortfall are assessed a financial penalty, while resources demonstrating excess performance are eligible for bonus payments. Portfolio netting – the use of multiple resources to satisfy the capacity commitment of a single resource – is not permitted.

Conditions on Oct. 2

Maintenance Season

The Oct. 2 PAI event took place during the peak of the fall maintenance season, which occurs between Sept. 16 and Dec. 31. Generally, lighter grid demand allows generators and transmission operators valuable time to temporarily disconnect and perform maintenance or make upgrades to their assets such as generators, transmission lines or substations. This necessary maintenance can significantly reduce the availability of the approximately 180,000 MW of total generating capacity in the PJM footprint.

The maintenance activity peaks in October and April, with about 2,400 separate planned transmission outages during each of those two months and more than 50,000 MW of generator outages.

Generation Outages

Because a variety of generators typically are out of service for maintenance during this time, significantly reducing the resources available to serve load, PJM issued an alert on the afternoon of Oct. 1 – called a Maximum Generation Emergency/Load Management Alert – to provide an early alert that system conditions may require the use of the PJM Emergency Procedures. It is implemented when Maximum Emergency generation is called into the operating capacity or if demand response is projected to be implemented.

Preliminary outage rates, calculated from eDART¹ installed capacity and outage reduction amounts, are shown in Figure 2. The pre-scheduled outage rates² (Planned and Maintenance Outages) in the PAI zones were significantly higher than in PJM overall. Forced outage rates in the PAI zones were slightly higher than in PJM overall, although the difference was less dramatic than with the pre-scheduled outage rates. In both the PAI zones and the overall PJM footprint, the aggregate forced outage rates of Capacity Performance units was approximately 10 percent lower than the forced outage rates of non-Capacity Performance units.

¹ The PJM eDART system is an online portal that is used in real-time operations to track generating unit capabilities on a minute-by-minute basis. PJM Generation Owners (GO) submit unit forced/unplanned outages and reductions through this portal during the current operating period so that, at any given time, PJM dispatch can assess unit availability and maintain adequate reserves to ensure system reliability. When a GO submits an unplanned reduction or outage, the actual cause of a reduction, trip or start failure may not be known until much later and indeed may be different from the cause reported on the eDART ticket. This is partly due to the plant needing to focus on real-time operations at the initial trip with the expectation of a more detailed trip analysis when time permits. This is reconciled at the earliest by the 20th of the month following the month in which the outage occurred, using the Generator Availability Data System (GADS). For these reasons, it is important to emphasize that the generation outage data provided and any associated analysis is subject to reconciliation with GADS data. These values are not final and should not be used for any decision making purposes.

² PJM uses many factors to evaluate and approve pre-scheduled outages, however, unseasonable weather, such as the heat experienced in early October, can create challenges with outages that have been scheduled in advance. PJM has the ability to recall active Maintenance Outages and cancel unstarted Planned and Maintenance Outages to mitigate these challenges.

Figure 2. RTO and PAI Zone Outage Rates on Oct. 2, 2019

Wednesday, Oct. 2, 2019			12:00	13:00	14:00	15:00	16:00	17:00	18:00
RTO	Overall	Planned Outage Rate	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%	9.9%
		Maintenance Outage Rate	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%
		Forced Outage Rate	7.9%	8.1%	7.3%	7.0%	7.3%	7.2%	7.1%
	CP	Planned Outage Rate	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
		Maintenance Outage Rate	4.8%	4.8%	4.7%	4.7%	4.7%	4.7%	4.7%
		Forced Outage Rate	6.4%	6.6%	5.7%	5.5%	5.7%	5.6%	5.5%
	Non-CP	Planned Outage Rate	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
		Maintenance Outage Rate	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
		Forced Outage Rate	16.5%	16.7%	16.7%	16.2%	16.2%	16.2%	16.2%
PAI Zones (AEP, BGE, DOM, PEPCO)	Overall	Planned Outage Rate	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%
		Maintenance Outage Rate	3.6%	3.6%	3.5%	3.5%	3.5%	3.5%	3.5%
		Forced Outage Rate	8.9%	9.7%	9.5%	9.4%	9.5%	9.4%	9.3%
	CP	Planned Outage Rate	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%	17.3%
		Maintenance Outage Rate	3.6%	3.6%	3.4%	3.4%	3.4%	3.4%	3.4%
		Forced Outage Rate	7.5%	8.3%	8.1%	7.9%	8.1%	7.9%	7.8%
	Non-CP	Planned Outage Rate	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%
		Maintenance Outage Rate	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
		Forced Outage Rate	20.2%	21.1%	21.1%	21.1%	21.0%	21.3%	21.3%

Weather

On Oct. 1 and Oct. 2, 2019, the PJM footprint experienced extreme hot weather, especially for a day outside of the summer season. A significant portion of the PJM region was 10 to 20 degrees above normal (Figure 3). During this spell of hot weather, a large number of cities from the Ohio Valley to the East Coast tied or broke October temperature records (Figure 4).

Figure 3. Temperature Deviation from Normal

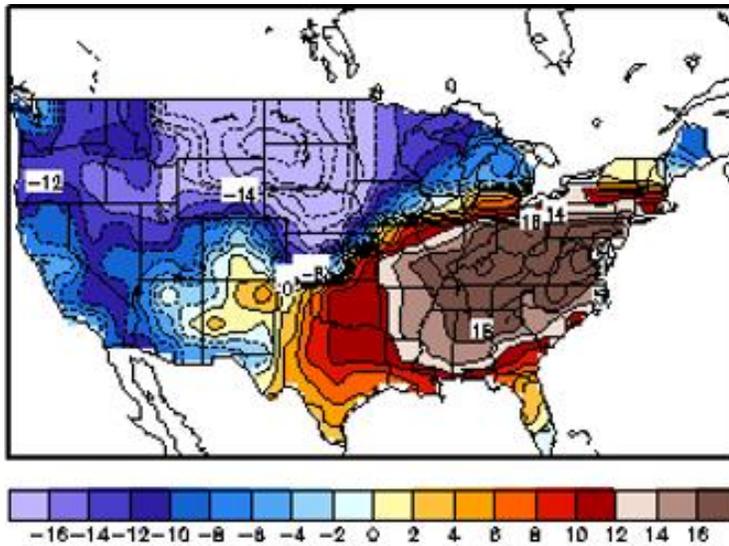


Figure 4. Cities Experiencing Record-Setting Heat Oct. 1 to Oct. 4



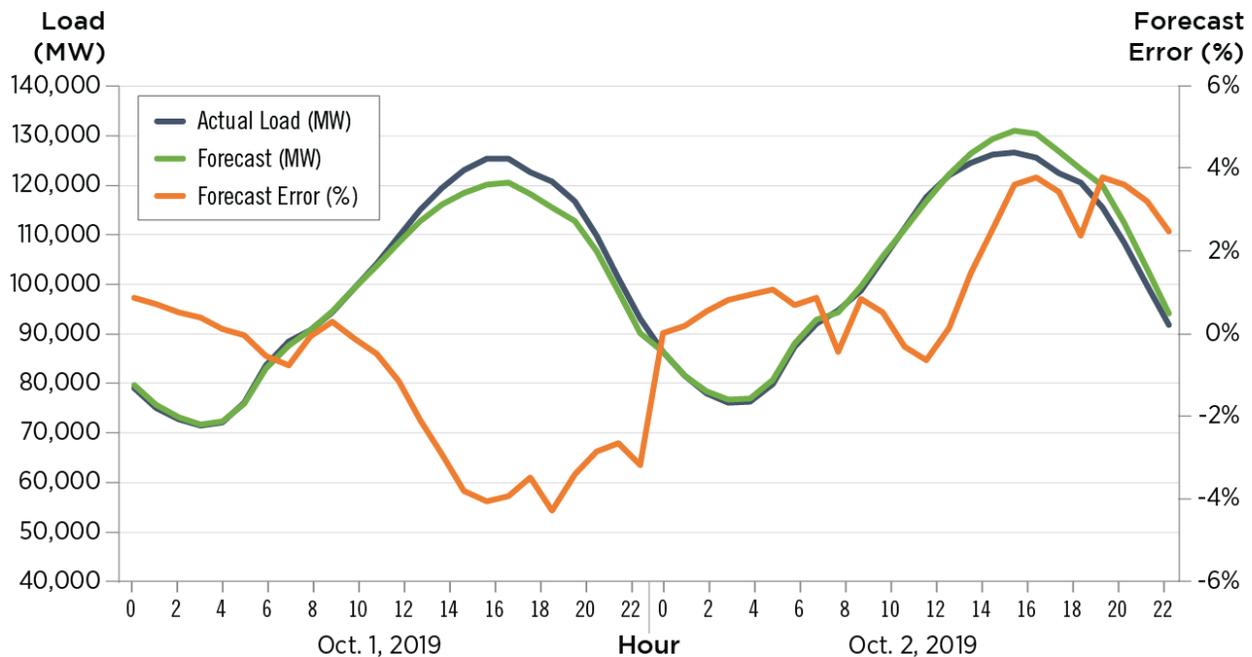
Additionally, on Oct. 2, a cold front was positioned just north of PJM, causing rain and clouds along PJM's northwestern border. As the front dropped south and east into the footprint, much cooler temperatures moved in behind it. This drop in temperature was expected, but progressed a few hours ahead of schedule, causing some temperature forecast error in northernmost cities in the ComEd and FE zones such as Chicago, IL, Cleveland, OH, and Toledo, OH.

Load Forecast

In order to create the final load forecast, PJM dispatchers use a suite of load forecast models that consist of pattern matching algorithms (models that forecast load by looking through historical data for similar weather patterns) and neural networks. One of the primary models is a temperature-based neural network, which uses temperature and the calendar – inputs like day of week and month of year – to forecast the load.

This model, and many of the others, rely on past days that look similar to the day that is being forecast. When the future day is out of the ordinary, such as a 90-degree day in October, the model has less historical data on which to base its forecast, or it may be considering incongruent data, such as 90-degree days in early September during which load may react very differently. It is common for load forecast models to underestimate load on extreme temperature days, especially in shoulder months when similar days are hard to find in the historical record. This was the case on Oct. 1 and was expected to be the case again on Oct. 2. However, while the load forecast was low for Oct. 1, it was high on Oct. 2 (Figure 5) for the reasons outlined below.

Figure 5. Load Forecast versus Actual Load on Oct. 1 and Oct. 2



In addition to the models not having a large selection of similar historical days to work with, the early arrival of the cold front also complicated conditions. Since temperatures are such a critical input to load forecasting, temperature forecast error is a typical cause of load forecast error and accounts for part of the load forecast error on Oct. 2.

Load forecast error refers to the difference between forecasted and actual load values – not a mistake or miscalculation.

Temperatures were well forecasted in the cities that were not impacted by the cold front; the average weather forecast error for 17:00 was 1.6 degrees once the cities in the ComEd and ATSI zones are excluded. The zones impacted by the early arrival of the cold front, experienced characteristic load

forecast error, with the load coming in below the forecast due to cooler-than-expected temperatures. Of the 4,600 MW of load forecast error at the peak hour on Oct. 2, error in ComEd and ATSI made up about 50 percent.

Operations Timeline

The Week Before: Sept. 24–29

During the last week of September 2019, weather services were forecasting unusually hot temperatures for the first week in October. By Friday, Sept. 27, PJM's weather services were predicting temperatures in the upper 80s and low 90s in the western part of PJM for Tuesday, Oct. 1, with widespread 90 degree temperatures across most of PJM on Wednesday, Oct. 2.

The high system loads anticipated for Oct. 1 and Oct. 2, combined with scheduled generation and transmission outages, were expected to create challenging operating conditions. PJM staff began evaluating generation and transmission outages. On Friday, Sept. 27, PJM turned off the generation auto-approval feature in eDART, which approves generation outages, provided there are sufficient resources to reliably meet system needs for the future period.

PJM staff worked with transmission owners and generation owners to identify equipment on outage that could be returned to service. PJM staff also evaluated pending transmission outages and worked with the transmission owners to reschedule the work until after the high temperatures.

Approximately 1,200 MW of generation resources adjusted their maintenance schedules so that they would be available for the pending peak load days; however, no units already on maintenance outages were recalled 72 hours in advance³ because projections did not indicate that this was necessary. PJM staff cancelled or deferred 134 transmission outages that were scheduled for the first week in October and two transmission facilities that were out of service for long-term maintenance activities were returned to service. Even with these efforts, there were 584 active transmission tickets and over 45,000 MW of generation was on outage.

Weather services continued to refine their forecasts for the week of Sept. 30 through Oct. 6. Temperatures were expected to be warmer on Tuesday, Oct. 1 and peak across most of the PJM on Wednesday, Oct. 2, followed by more seasonal temperatures later in the week.

Monday, Sept. 30

As temperatures for most of the PJM footprint were expected to be in the 90s, PJM issued a Hot Weather Alert for Wednesday, Oct. 2, for the entire RTO except the ComEd Zone. The ComEd zone was excluded because temperatures in ComEd were forecast to be below 90 degrees on Oct. 2, as a cold front was expected to move into the western part of PJM. The peak load for Monday, Sept. 30 was 109 GW and there were no significant operational issues.

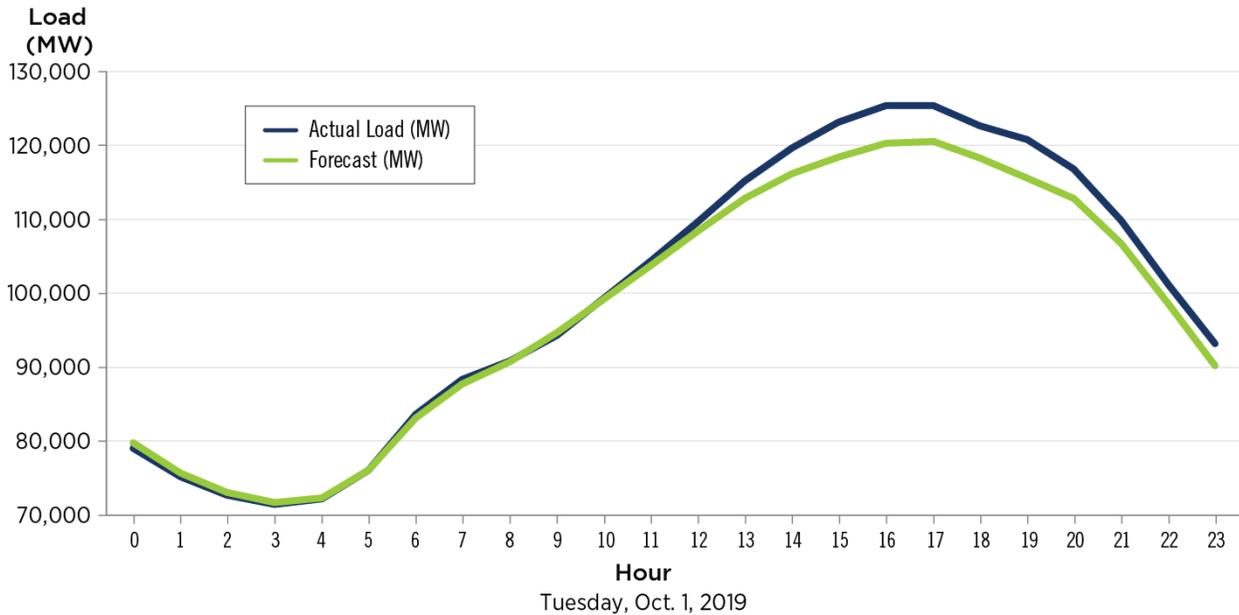
³ For more information, please see Manual 10, Section 2.3.2

Tuesday Oct. 1

Heading into the Oct. 1 operating day, the PJM peak load was expected to be 120 GW at hour ending (HE) 18.⁴ PJM had sufficient resources to serve the load and satisfy our reserve requirements; however, congestion was expected on the system as transmission constraints would limit resources that would otherwise be used to serve the load.

Approaching evening peak, it became clear that we would exceed the expected peak load. PJM continued to add generation as the load increased throughout the afternoon. At one point, as load was increasing, PJM called upon its synchronized reserve tools to ensure load/supply balance. PJM requested synchronized reserves be deployed and requested shared reserves from NPCC. Prices on the system were much higher as we headed into the evening peak, and shortage pricing was triggered for several intervals. Ultimately the peak load for Tuesday was 125.5 GW for HE 18, which was over 5,000 MW above the forecast heading into the operating day (Figure 6).

Figure 6. Actual Load vs. Forecast Load for Oct. 1



On Tuesday, Oct. 1, the load cleared in the Day-Ahead Market for Wednesday, Oct. 2, was approximately 121 GW. As temperatures across most of PJM were expected to be higher on Wednesday, Oct. 2, than they were on Tuesday, Oct. 1, the load forecast for Wednesday was increased to just over 132 GW. To serve that load and cover day-ahead scheduling reserves, Maximum Emergency Generation was called for the next day. As a result, on Oct. 1, PJM issued a Maximum Generation Emergency/Load Management Alert for Oct. 2.

System conditions for Oct. 2 were expected to be more challenging than PJM had experienced on Oct. 1. Load was expected to be higher, so additional resources would be required to serve the load and satisfy PJM's reserve obligations. Transmission congestion patterns were expected to be similar to Oct. 1.

⁴ Hour ending (HE) is a term that denotes the time period of the preceding hour (e.g., 12:01 a.m. to 1:00 a.m. is hour ending 1).

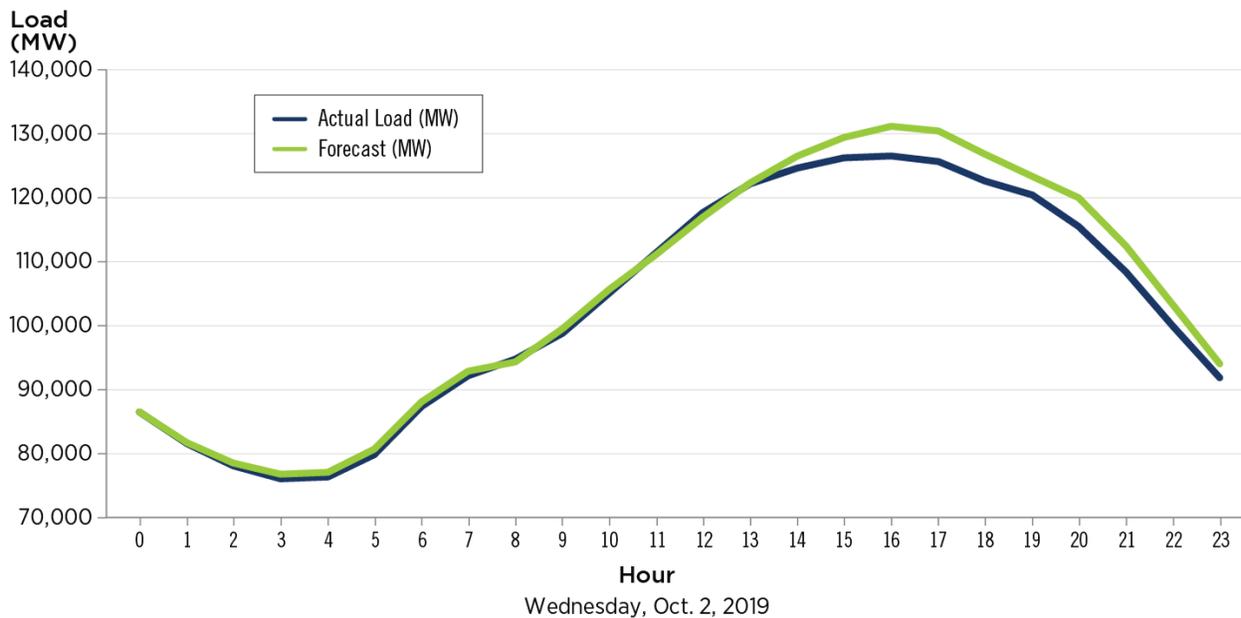
Transmission constraints on Tuesday were expected to limit the generation that would otherwise be available to serve load. Studies showed that a significant amount of the generation that was available would not be able to be utilized to full capability due to these transmission constraints.

Wednesday, Oct. 2

As we headed into the Oct. 2 operating day, PJM’s overall capacity position deteriorated as some generation was lost after the evening peak on Tuesday. At 5:45,⁵ the Maliszewski–Vassell 765 kV line in Ohio tripped due to failed substation equipment, which was expected to exacerbate congestion concerns and further limit available generation. In addition, several generators that were expected to be available for the peak notified PJM that they were either not going to be able to come online or would be delayed until after the peak for the day.

Throughout the morning, load continued to come in as forecast (see Figure 7).

Figure 7. Actual Load vs. Forecast Load for Oct. 2



⁵ Times in this paper use the 24-hour clock.

Between 12:00 and 14:00, approximately 1,933 MW of non-firm exports were recalled (Figure 8). None of these exports were capacity-backed.

Figure 8. Non-Firm Exports



At noon, given the generation performance and the expectation that some of the available generation would not be able to be ramped to maximum output due to transmission constraints, PJM issued a Pre-Emergency Load Management Reduction Action for demand resources with a two-hour lead time⁶ to be implemented by 14:00 in the AEP, Dominion, BGE and PEPCO transmission zones.

These zones were selected because the load reduction would not only help the overall load/capacity issue, but reduced load in these zones would also help to manage transmission constraints.

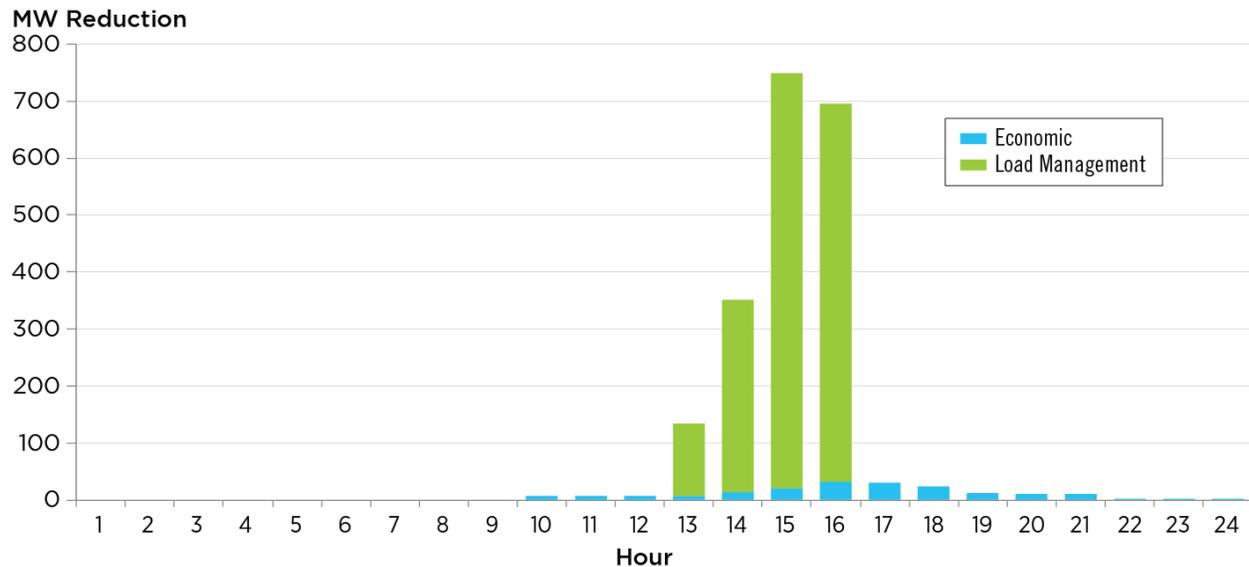
For the AEP, BGE, Dominion and PEPCO zones, there was 728 MW of 120-minute (Figure 9), 43 MW of 60-minute, and 888 MW of 30-minute load management reported as available by the Curtailment Service Providers. The Pre-Emergency Load Management Reduction Action was for both Capacity Performance and base demand response (DR). However, only Capacity Performance DR was obligated to respond since the event was outside the base DR compliance period of June to September. Even though it was outside the compliance period for base demand response, PJM anticipated some response from base DR.

⁶ PJM normal protocol is to deploy the 120-minute lead time resources before the 60- or 30-minute lead time resources in case system conditions deteriorate and because they are less expensive. This allows PJM to reserve the shorter and more expensive lead time resources for later deployment. PJM will typically deploy the 30-minute DR resources first if there is an unforeseen problem such as a unit tripping offline and 120-minute lead time resources take too long to address the immediate issue. The energy price caps are higher for shorter lead time resources: 120-minute lead time resources = \$1,100, 60-minute lead time resource = \$1,425, 30-minute lead time resources = \$1,849.

Figure 9. Base and CP Demand Response Megawatts by Zone

	AEP	BGE	DOMINION	PEPCO	Total
CP DR	23.3	0.2	0	1.9	25.4
Base DR (2 hour)	426.7	239.8	4	32.1	702.6
Total	450	240	4	34	728

Figure 10. Estimated Demand Response in PJM⁷



Load continued to increase as expected. At approximately 14:00, the rate of load increase declined considerably. Some reduction in the rate was expected due to the pre-emergency load management, however, the amount of load reduction significantly exceeded the load reduction that was expected in all zones in which it was called.

By 15:00, the load was several thousand megawatts below the load forecast curve. Pre-emergency load management was cancelled in the Dominion, BGE and PEPCO zones at 15:45 and in the AEP zone at 16:00. The peak load for the day ended up at approximately 126,500 MW at HE 17.

⁷ Load Management Amounts are CSP-estimated expected reductions. Actual load reductions are not finalized until up to three months after event

Pricing Outcomes

Tuesday, Oct. 1, 2019

On Oct. 1, load materialized in higher quantity and more quickly than what had been forecast. The day was also met with high congestion causing higher than normal Locational Marginal Prices (LMPs) across the PJM region (Figure 11). The high congestion also caused several constraints to bind at the penalty factor⁸ (Figure 12) which contributed to hourly LMPs exceeding \$200/MWh between hour beginning (HB) 2–5 p.m. with a maximum PJM-RTO price of \$691/MWh for HB 3 p.m.

Figure 11. Real-Time Hourly LMPs – Oct. 1

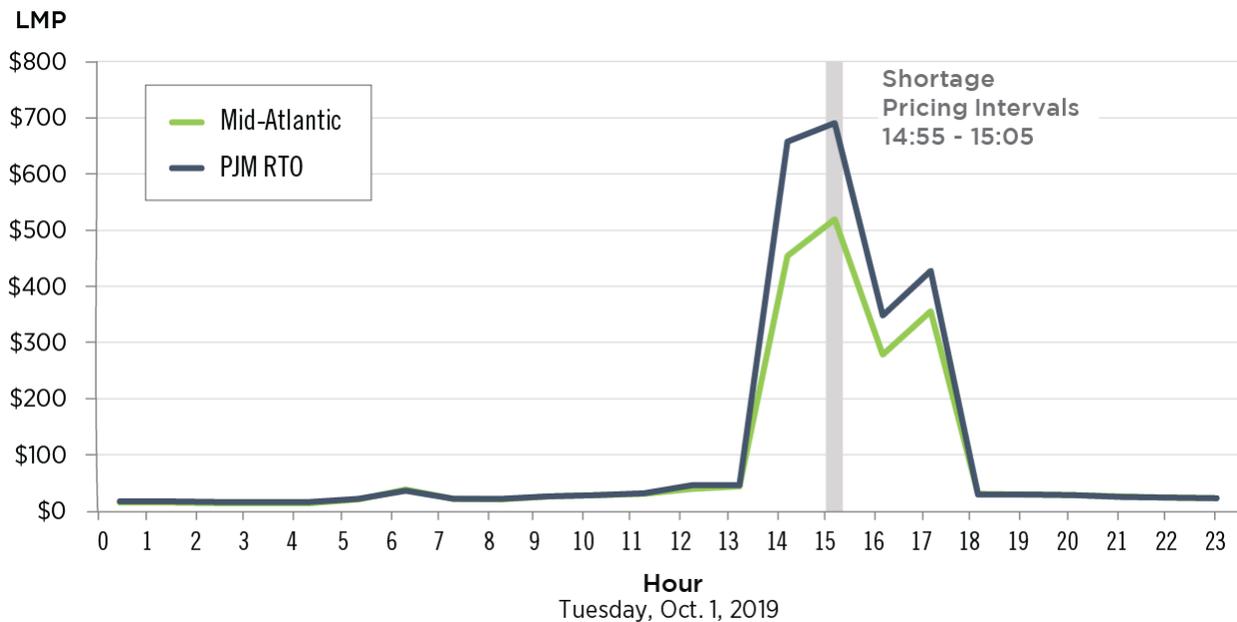


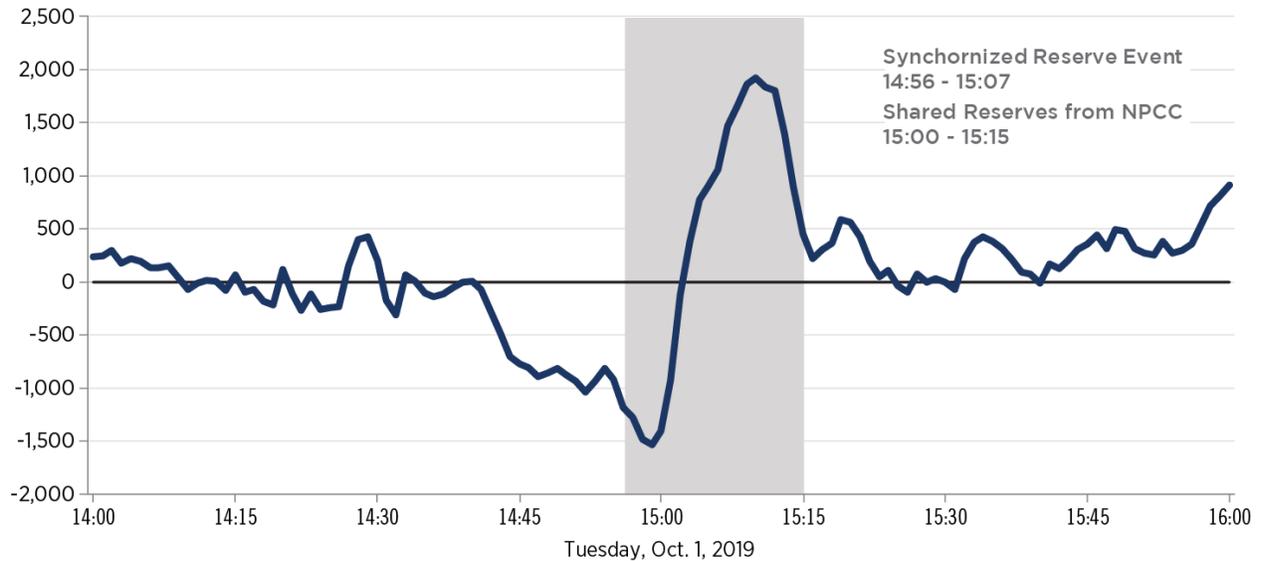
Figure 12. Constraints Binding at the Penalty Factor in Interval 15:00

Constraint Name	Contingency	Marginal Value (\$/MWh)
CONASTON 5012/3-500B GCB C 500 KV	L500.Hunterstown-Conastone.5013	-\$2,000.00
CONASTON 5012/3-500B GCB C 500 KV	BASE	-\$2,000.00
CONASTON-PEACHBOT 5012 B 500 KV	BASE	-\$2,000.00
HAVILAND J CB 138 KV	345/138.EastLima.T1	-\$2,000.00
PRGEORGE TX1 XFORMER H 230 KV	L230.Chuckatuck-Surry.290	-\$2,000.00
YUKON TRAN 4 XFORMER H 500 KV	500/138.Yukon.T1 & T3 (Sctnlz F)	-\$2,000.00

⁸ From Manual 11, Section 2.17 – Transmission constraint penalty factors are parameters used by the Market Clearing Engines (MCE) to specify the maximum cost willing to be incurred to control a transmission constraint. The ultimate effect of the transmission constraint penalty factor is that it limits the controlling actions the MCE can take to resolve a constraint by limiting the cost that is willing to be incurred to control it. All PJM internal constraints, regardless of voltage level, are defaulted to a \$2,000/MWh transmission penalty factor in the Real-Time Energy Market. When a constraint binds at the penalty factor, it indicates that insufficient resources are available to control the constraint at a cost less than or equal to the penalty factor.

Around hour beginning 3 p.m., PJM also experienced low ACE⁹ control (Figure 13), and, in order to keep up with demand, a Synchronized Reserve Event was triggered at 2:56:04 p.m. on Oct. 1, 2019. During this event, the available ramping capability on reserve resources was deployed to meet energy needs, leaving system reserves short of the synchronized reserve requirement which resulted in three intervals of reserve shortage (2:55, 3:00, 3:05 p.m.). Shortage pricing is triggered when reserves are being priced off of the demand curve for a given reserve product and reserve zone or sub-zone¹⁰.

Figure 13. Area Control Error (ACE)



The energy component of LMP is set by the resource that can serve the next increment of load at the least cost. However, the cost of serving the next megawatt of load is not based solely on the resource’s incremental energy offer. The congestion impact from the delivery of that additional megawatt is also considered when calculating the cost of that marginal megawatt. In addition, if the next increment of load requires converting a megawatt of reserves into a megawatt of energy, and this exacerbates reserve shortage conditions, the reserve penalty factors will be incorporated into energy prices. All of these factors contributed to an energy component of LMP of \$3,644.16/MWh in the 3 p.m. interval (Figure 14).

⁹ Area Control Error is a measure of the imbalance between sources of power and uses of power within the PJM RTO. This imbalance is calculated indirectly as the difference between scheduled and actual net interchange, plus the frequency bias contribution to yield ACE in megawatts.

¹⁰ From Manual 11, Section 4.2.2.1 – The reserve demand curves are used to articulate the value of maintaining reserves at specified levels and ensure product substitution between energy and reserves up a specified penalty factor. The penalty factor represents the price at which reserves will be valued if the desired reserve MW cannot be met with the available reserves on the system, and also acts as a price cap beyond which reserves will not be procured through market clearing.

Figure 14. Characteristics of the Oct. 1 Shortage Pricing Intervals¹¹

	Interval	Energy LMP (\$/MWh)	RTO RMCP (\$/MWh)	MAD SRMCP (\$/MWh)	MAD NSRMCP (\$/MWh)	RTO SRMCP (\$/MWh)	RTO NSRMCP (\$/MWh)	Shortage (Segment)
Oct. 1, 2019	14:55	2,550.21	3,756.92	616.44	16.44	316.44	16.44	MAD SR (2) RTO SR (2)
	15:00	3,644.16	5,064.39	1,150	300	1,150	300	MAD SR (2) RTO SR (2) RTO PR (1)
	15:05	912.83	1,104.42	693.23	93.23	393.23	93.23	MAD SR (2) RTO SR (2)

Wednesday, Oct. 2

With the continued hot weather, Oct. 2, 2019, was also met with high congestion throughout the day. PJM's RTO Regulating requirement is 525 effective MW during non-ramp hours and 800 effective MW during ramp hours¹² The Regulation requirement for non-ramp hours was increased to 800 effective MW given expected system conditions. There were ample synchronized reserves and primary reserves to meet the reserve requirements throughout the day; therefore, shortage pricing was not triggered on the Oct. 2.

Load Management did not set price throughout the PAI because it was not identified as the marginal resource. LMPs are set based on the offer price of the resource that can serve the next increment of load at the lowest cost. Given that load came in lower than forecasted throughout the duration of the load management deployment, there was ample unloaded generation available to serve load at a lower cost than the offer price of the pre-emergency load management. One of these resources was identified as marginal and therefore set energy prices.

With enough generation and reserves on the system, no transient shortage conditions were experienced. LMPs did not reach as high as the previous day, and there was still significant congestion throughout the day¹³, which caused several zones to have very low to negative LMPs (Figure 15).

¹¹ LMP – Locational Marginal Price RMCP – Regulation Market Clearing Price SRMCP – Synchronized Reserve Market Clearing Price NSRMCP – Non-Synchronized Marker Clearing Price

¹² For more information, please see Manual 12, Section 4.4.3

¹³ The list of active constraints for any given day can be found here: https://dataminer2.pjm.com/feed/rt_marginal_value

Figure 15. Real-Time Hourly LMPs – Oct. 2

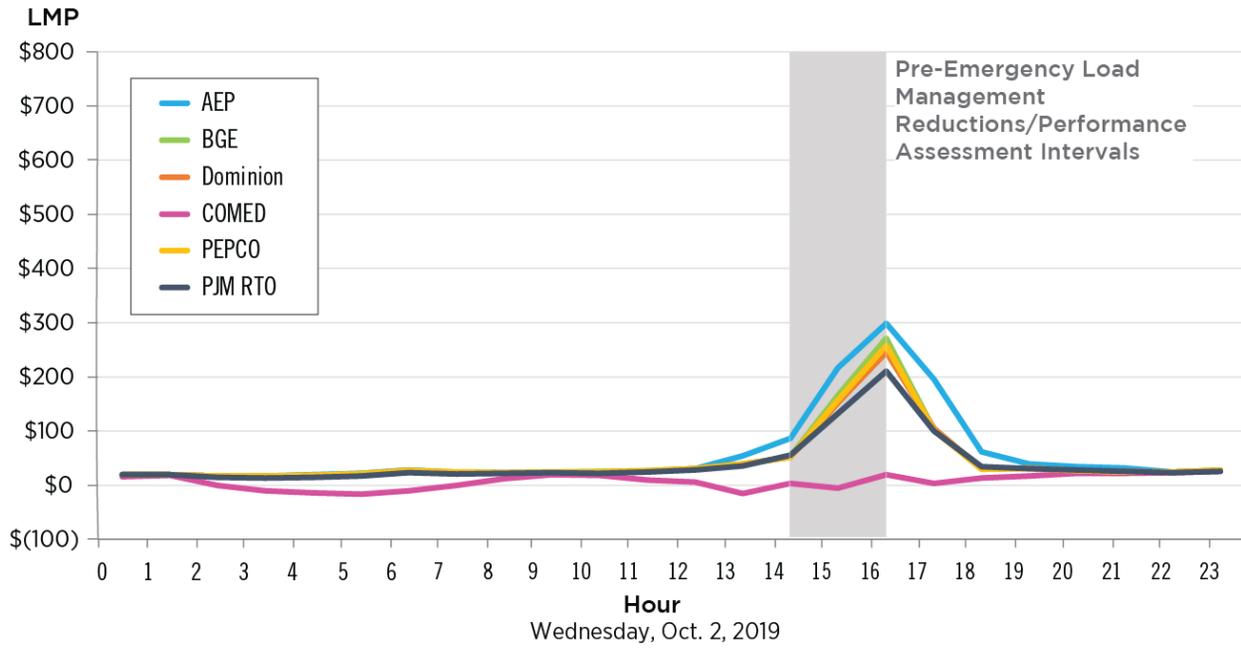


Figure 16 summarizes the energy, reserve and regulation prices during the PAI event.

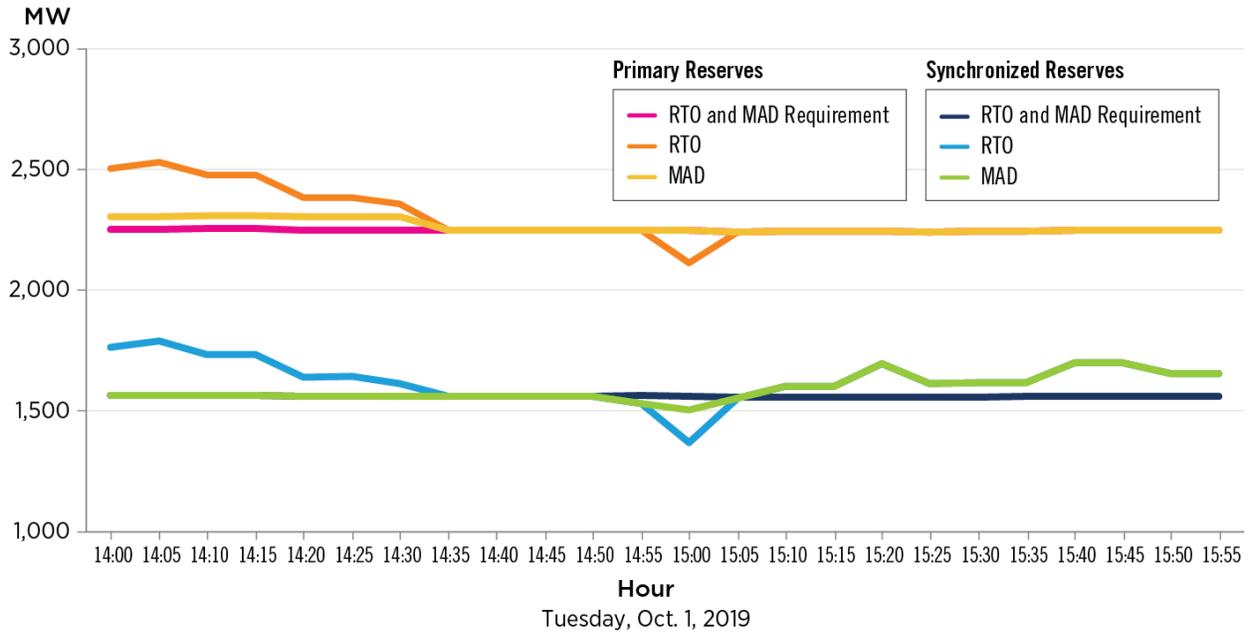
Figure 16. Energy, Reserve and Regulation Prices During the PAI

Interval	Energy LMP (\$/MWh)	Min Zonal LMP	Max Zonal LMP	RTO RMCP (\$/MWh)	MAD SRMCP (\$/MWh)	MAD NSRMCP (\$/MWh)	RTO SRMCP (\$/MWh)	RTO NSRMCP (\$/MWh)
Oct. 2, 2019	14:00	\$40.15	-\$29.06	\$116.81	\$59.10	\$0.00	\$0.00	\$0.00
	14:05	\$34.81	\$3.55	\$47.55	\$22.70	\$0.00	\$0.00	\$0.00
	14:10	\$41.57	\$8.81	\$54.47	\$28.78	\$5.00	\$5.00	\$5.00
	14:15	\$40.97	-\$11.80	\$58.03	\$40.27	\$5.00	\$5.00	\$5.00
	14:20	\$40.97	-\$11.80	\$58.03	\$40.08	\$5.00	\$5.00	\$5.00
	14:25	\$68.05	\$10.89	\$136.36	\$44.50	\$0.00	\$0.00	\$0.00
	14:30	\$66.25	\$12.42	\$133.17	\$43.06	\$2.09	\$0.00	\$2.09
	14:35	\$66.25	\$12.42	\$133.17	\$43.06	\$2.09	\$0.00	\$2.09
	14:40	\$51.22	\$7.12	\$106.34	\$32.50	\$0.00	\$0.00	\$0.00
	14:45	\$51.22	\$7.12	\$106.34	\$32.50	\$0.00	\$0.00	\$0.00
	14:50	\$79.99	\$12.61	\$158.52	\$56.99	\$0.00	\$0.00	\$0.00
	14:55	\$79.99	\$12.61	\$158.52	\$56.99	\$0.00	\$0.00	\$0.00
	15:00	\$79.99	\$12.61	\$158.60	\$66.18	\$0.00	\$0.00	\$0.00
	15:05	\$177.41	-\$49.99	\$521.30	\$160.45	\$7.50	\$7.50	\$7.50
	15:10	\$194.99	-\$28.21	\$547.61	\$198.32	\$5.00	\$5.00	\$5.00
	15:15	\$162.11	-\$59.56	\$474.90	\$153.05	\$3.50	\$3.50	\$3.50
	15:20	\$198.52	-\$17.40	\$545.53	\$196.15	\$5.00	\$5.00	\$5.00
	15:25	\$123.37	-\$1.02	\$293.47	\$105.72	\$3.50	\$3.50	\$3.50
	15:30	\$123.37	-\$1.02	\$293.47	\$105.79	\$3.50	\$3.50	\$3.50
	15:35	\$82.28	\$19.25	\$175.87	\$62.41	\$7.50	\$7.50	\$7.50
15:40	\$82.46	\$17.91	\$176.31	\$61.82	\$0.00	\$0.00	\$0.00	
15:45	\$83.04	\$20.38	\$176.72	\$62.84	\$3.50	\$3.50	\$3.50	
15:50	\$84.54	\$8.96	\$188.76	\$62.45	\$0.00	\$0.00	\$0.00	
15:55	\$184.61	\$12.49	\$352.11	\$189.20	\$0.00	\$0.00	\$0.00	
16:00	\$106.25	\$20.65	\$193.48	\$123.52	\$0.00	\$0.00	\$0.00	

Reserves

The real-time reserve shortage that occurred on Oct. 1 is shown in Figure 17. On Oct. 2, shown in Figure 18, real-time reserves met or exceeded the reserve requirements for both the RTO and MAD areas. Following the Hot Weather Alert, the Day Ahead Scheduling Reserve for Oct. 2 was increased¹⁴.

Figure 17. Reserves on October 1¹⁵



¹⁴ M11 Section 11 details the procurement procedure and requirements for DASR; M13 Section 2 details the current reserve requirements. The DASR Requirement adheres to the requirements for Day-Ahead Scheduling [30-minute] Reserve defined by Reliability First Corporation and all applicable reliability councils for areas within the PJM RTO. Following the issuance of a Hot or Cold Weather Alert or escalating emergency procedures as defined in PJM Manual 13: Emergency Operations for the RTO, Mid-Atlantic Dominion, or Mid-Atlantic region, PJM increases the DASR requirement to reflect the additional reserves typically carried under such conditions and to ensure that adequate resources are procured to meet real-time load and reserve requirements. The increase in DASR is detailed in M11 Section 11.2.1. The DASR is cleared via a simultaneous optimization with the Day-Ahead Energy Market based on bid-in parameters and eligibility. For 2019 the annual reserve requirement was calculated to be 5.9%. Real-time reserve requirements on October 1st and 2nd adhered to the standards defined in M13.

¹⁵ The Primary Reserves are composed of synchronized and non-synchronized resources. There is no requirement for non-synchronized reserves. Therefore, the primary reserves requirement can be satisfied by both synchronized and non-synchronized resources.

Figure 18. Reserves on October 2

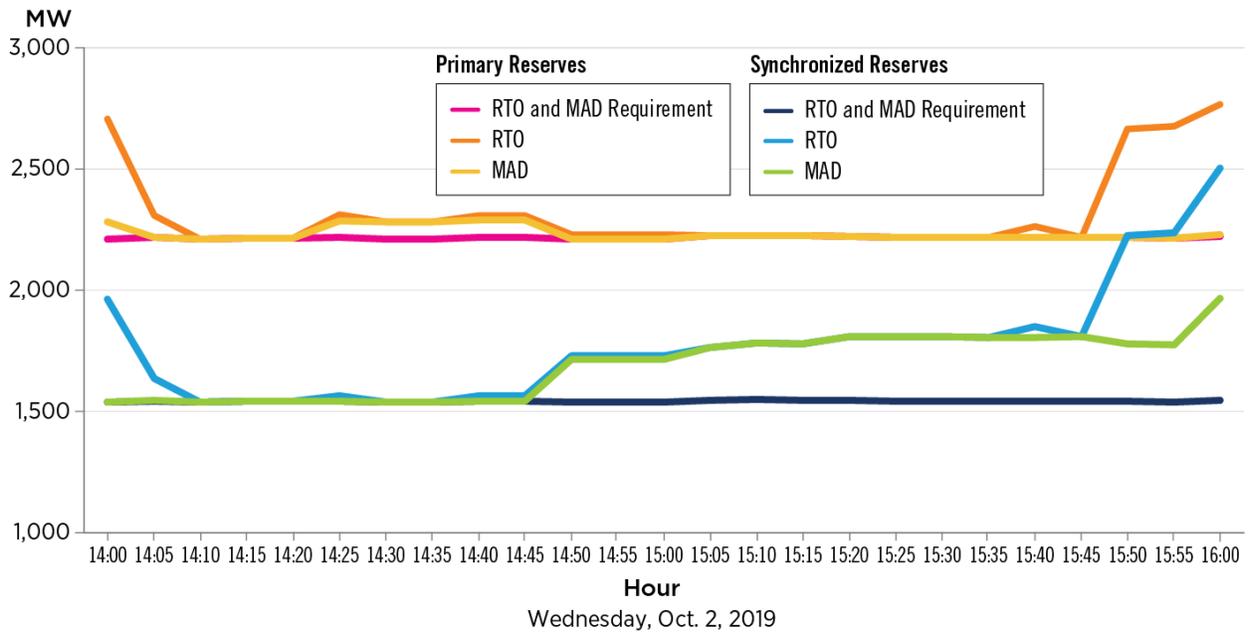
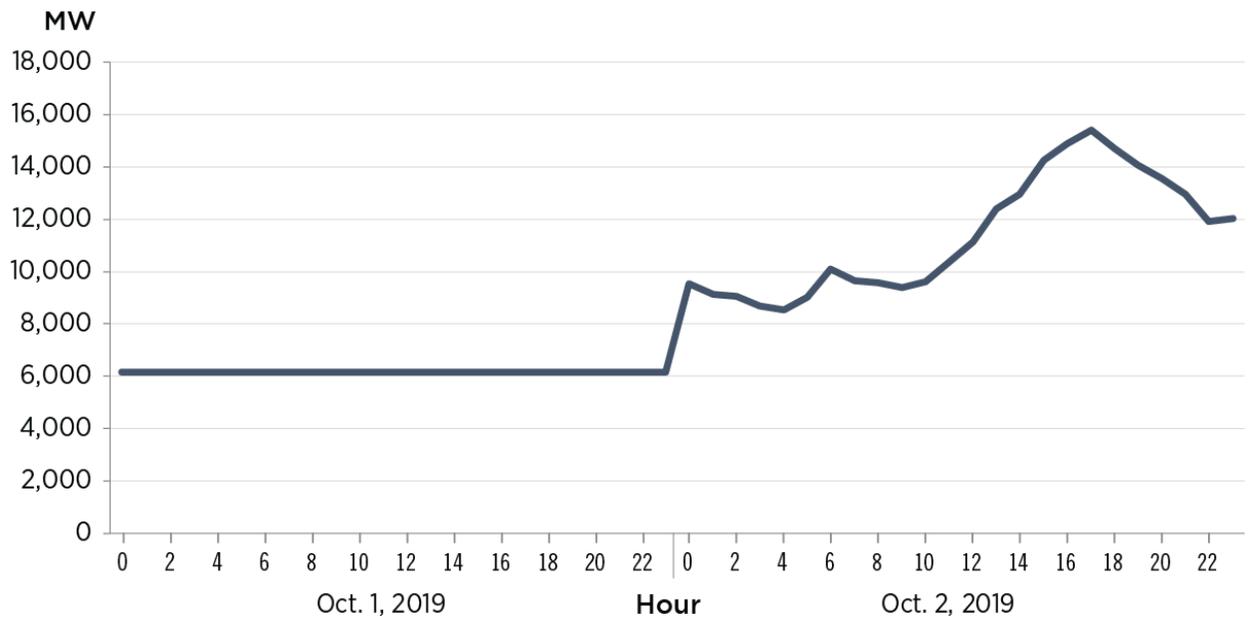


Figure 19. Day-Ahead Scheduling Reserve



Uplift

Preliminary uplift¹⁶ charges for Oct. 1:¹⁷

- **Total Uplift:** \$828,779
- **Lost Opportunity Cost:** \$328,816
- **Balancing Operating Reserve:** \$491,210

PJM classifies days where total uplift exceeds \$800,000 as a high uplift day. The primary driver for Lost Opportunity Cost credits on Oct. 1 was a result of transient Real-Time LMP spikes during the shortage pricing intervals. Eligible units with a Day-Ahead award that were not run in real time due to system conditions may have accrued Lost Opportunity credits.¹⁸ The primary driver for Balancing Operating Reserve credits on Oct. 1 was units that were run for constraint control.

Preliminary uplift charges for Oct. 2:¹⁹

- **Total Uplift:** \$1,004,912
- **Lost Opportunity Cost:** \$143,626
- **Balancing Operating Reserve:** \$801,159

The primary driver for Lost Opportunity Cost credits on Oct. 2 was a result of Real-Time LMP spikes following the completion of the Load Management Event. These spikes can be attributed to the high number of constraints binding and several constraints binding at the penalty factor throughout the day, peaking from hour beginning 4 p.m. to 5 p.m. The primary driver for Balancing Operating Reserve credits on Oct. 2 was units that were run for constraint control resulting from bottled generation and high system loads.

¹⁶ Uplift payments are made to market participants for operating a unit under specific conditions as directed by PJM to ensure that they recover their total offered costs when market revenues are insufficient or when their dispatch instructions diverge from their dispatch schedule.

¹⁷ Uplift credits and charges are subject to change based on PJM Settlements rules

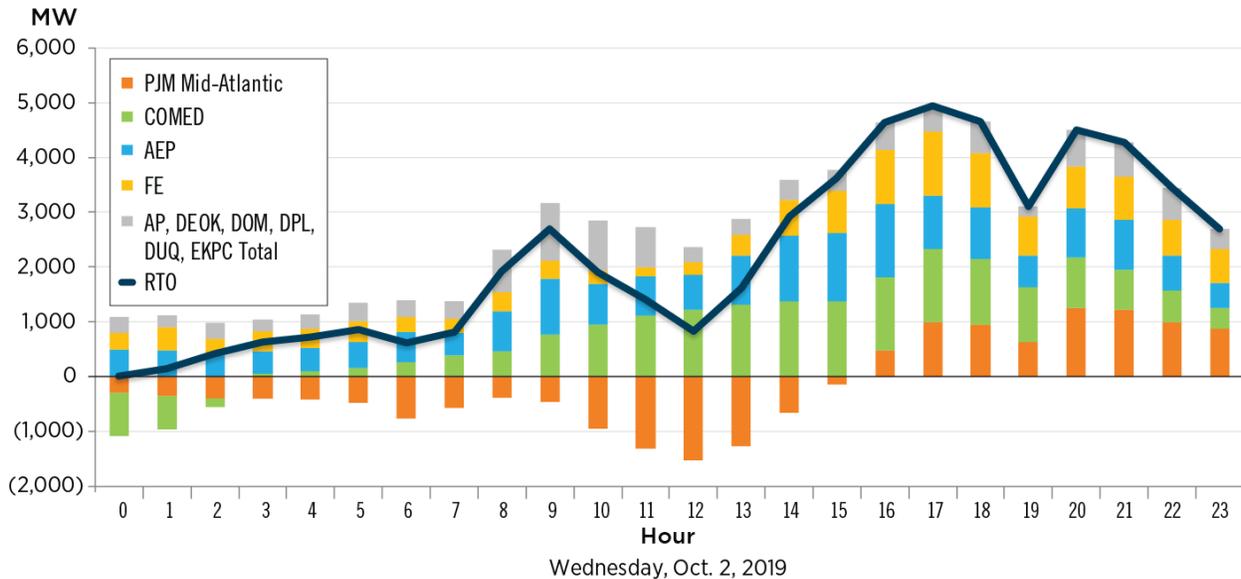
¹⁸ Please see Manual 28, Section 5 for more information about Balancing Operating Reserve and Lost Opportunity Cost payments.

¹⁹ Uplift credits and charges are subject to change based on PJM Settlements rules and do not include uplift credits associated with load management providers.

Where did the load go?

While PJM undertook emergency actions to assure reliable grid operations with cooperation by stakeholders, the Oct. 2 actual peak reached only 126,500 MW, significantly lower than the projected 132,000 MW forecast. 90 percent of the forecast error at peak can be attributed to four zones: ComEd (1,338 MW), AEP (1,333 MW), FE (989 MW), and PJM Mid-Atlantic (482 MW) (Figure 20).

Figure 20. Oct. 2 Forecast Error by Zone



The quick response of load-reducing resources, coupled with a cold front moving through Illinois and northern Ohio, only partially explains how demand drastically slowed its climb in the afternoon. PJM analyzed weather forecast error in the four zones with the highest contribution to overall load forecast error, as well as nodal load behavior, to determine why total load that day came in only 1,000 MW higher than the day before, despite temperatures being as much as 10 to 15 degrees higher in PJM's eastern zones.

Weather Analysis and Backcasting

Methodology

Temperature forecast error is one piece of the puzzle when deciphering load forecast error. Its contribution to load forecast error can be evaluated using a backcast. While load forecast models use temperature forecasts to produce a load forecast for a future day, a backcast utilizes the same model, but with actual temperature measurements from a historic day as the input, and outputs what the model's load forecast would have been that day if the temperature forecast was perfect. This process helps tease out the portion of the error that was caused by the temperature forecast compared to other potential sources of error, such as model error, human behavior and behind-the-meter generation.

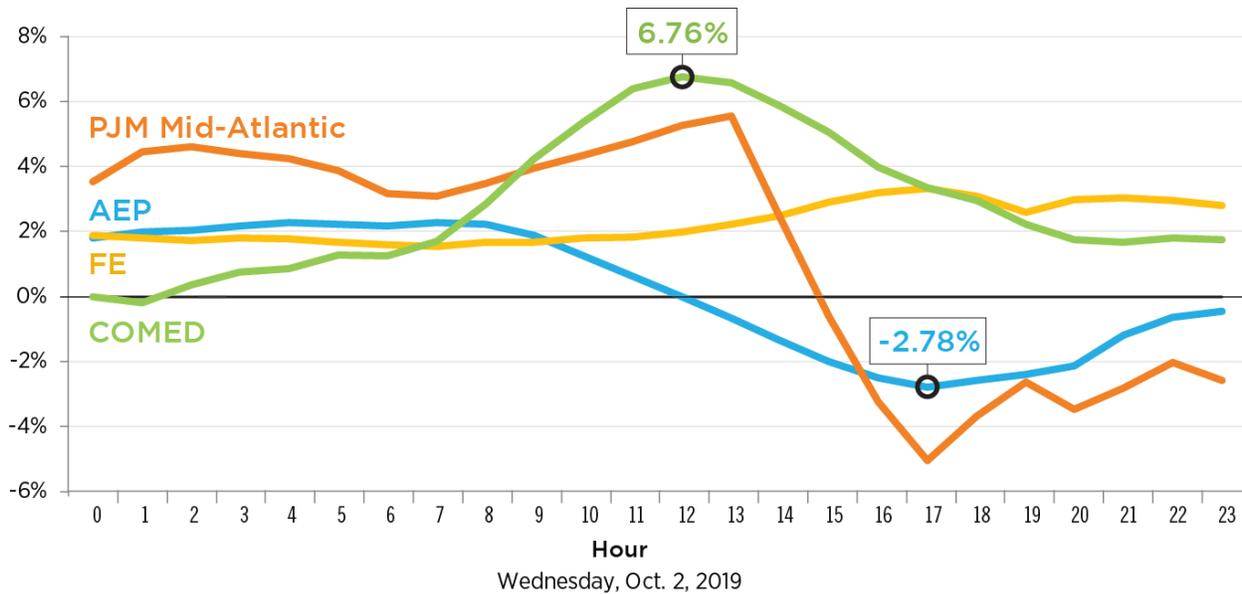
The backcast does not necessarily represent what PJM’s published forecast would have been. This final forecast is published only after a human operator reviews output from multiple neural network and pattern recognition models, studies weather conditions, and uses experience and training to manually adjust the forecast. The backcast, to the contrary, is fully automated and uses only one temperature-based neural network model. In spite of these differences, the backcast can provide great insight into the extent of error due to temperature.

Results from the backcast for Oct. 2 showed that a perfect temperature forecast would have improved the neural network forecast in ComEd by almost 500 MW and in ATSI by about 300 MW. However, many cities ended up being a few degrees warmer than expected, leading to backcasts that were higher than the original neural network forecasts. In fact, if the models had perfect knowledge of temperatures, the load forecast for the RTO overall would have been 3,000 MW higher.

Backcast Results and Conclusions

The difference between the backcast error and base neural network model error is presented for the four zones that were identified to have contributed the most to the Oct. 2 forecast error. In Figure 21, positive values indicate the backcast had greater accuracy than the base forecast, while negative values indicate the opposite.

Figure 21. Results of Backcast for Zones with the Greatest Contributions to Forecast Error



Case Study: ComEd load forecast error attributed to temperature forecast error

The most positive value in Figure 21 – 6.76 percent at 1 p.m. – is from ComEd, and is calculated by subtracting the backcast error of 1.71 percent, from the base forecast error of 8.47 percent. Because the load forecast model performs with great accuracy when a perfect temperature forecast is used, we can conclude with high confidence that the early arrival of a cold front (which counts in PJM parlance as ‘weather forecast error’) was the primary driver for load forecast error in ComEd.

This conclusion is further supported by 0, which plots the actual load, base neural net forecast, final forecast after adjustments from human operator, and the backcast. Beginning around Hour Ending 7 a.m., the orange line

representing the backcast is far closer to the navy blue line, representing the actual load, than either of the lines that represent the load forecasts. This continues consistently throughout the remainder of the day.

The temperature forecast in ComEd was 3 to 5 degrees hotter than the actual temperatures during the PAI event. Additionally, temperature forecasts were as much as 10 degrees higher than actual temperatures earlier in the day (Figure 23). This supports the hypothesis that a cold front moving through the Midwest caused cooler than expected temperatures, which in turn reduced electricity demand in that area. FirstEnergy appears to exhibit some of this behavior as well, but the explanatory power of temperature is less than it is for ComEd.

Figure 22. Results of COMED Backcast

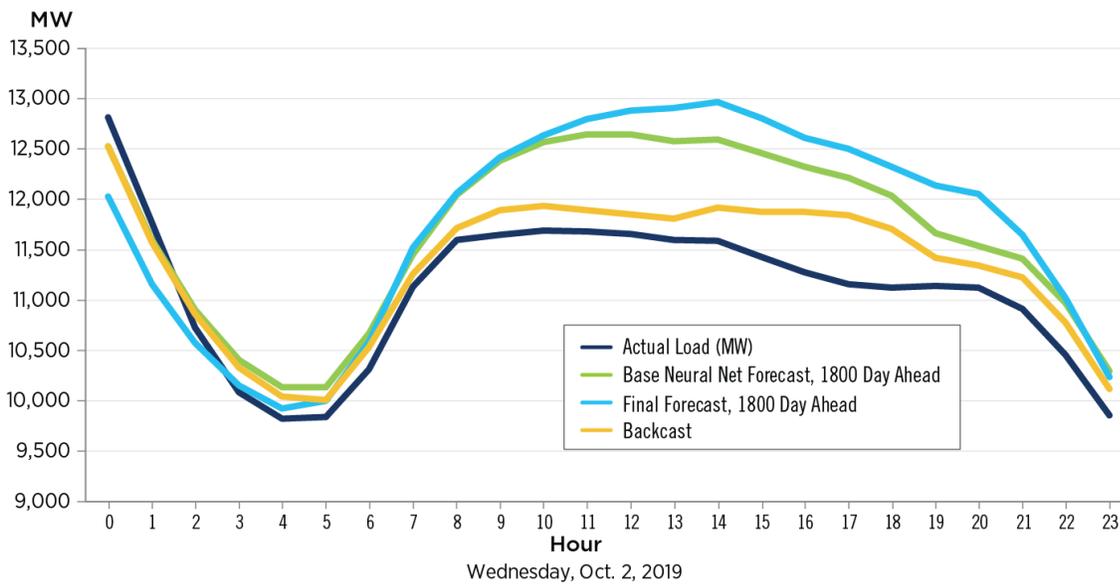
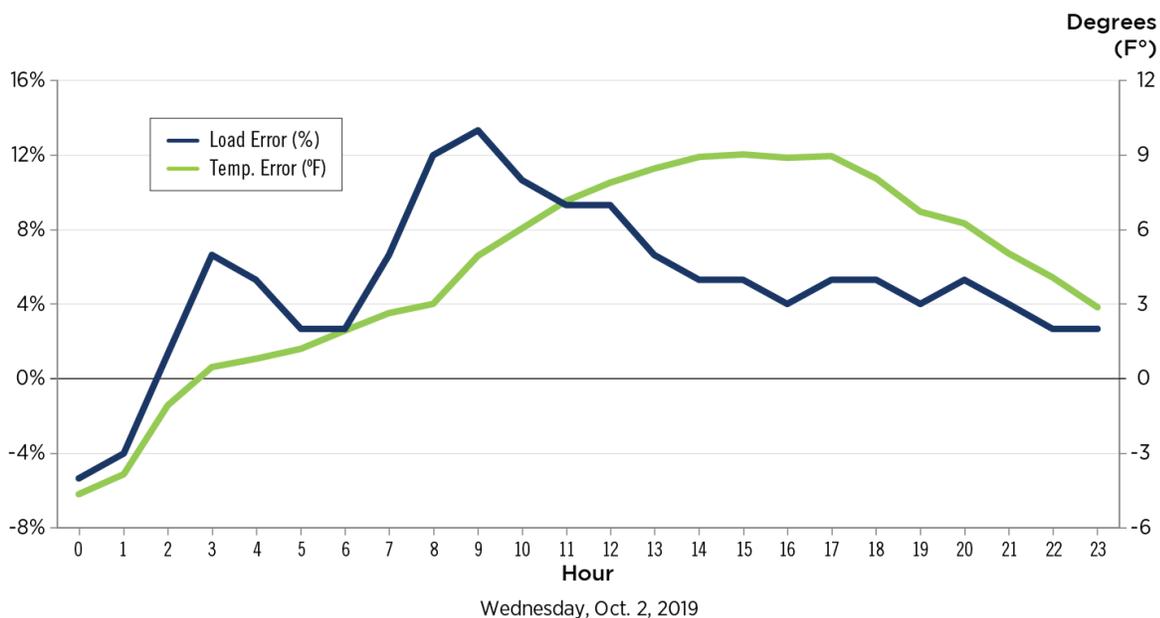


Figure 23. Results of COMED Temperature Error Analysis



Case Study: AEP – Temperature forecast error ruled out as cause of load forecast error

The behavior of AEP in Figure 24 is a case of perfect temperature data leading to less accurate load forecast. While the actual temperature was even hotter than expected, load came in lower than forecasted. Figure 24 shows the backcast (orange line) is even further from the actual load (navy blue line) than the forecasts during the peak of the day. Figure 25 demonstrates forecast error for load and temperature; the actual temperature was 2 to 4 degrees higher than what had been forecasted for the PAI event, yet AEP still experienced a far lower load than expected. To a similar degree, the same phenomenon is also observed in PJM Mid-Atlantic, requiring that we look for alternative sources of error in AEP and PJM Mid-Atlantic.

Figure 24. Results of AEP Backcast

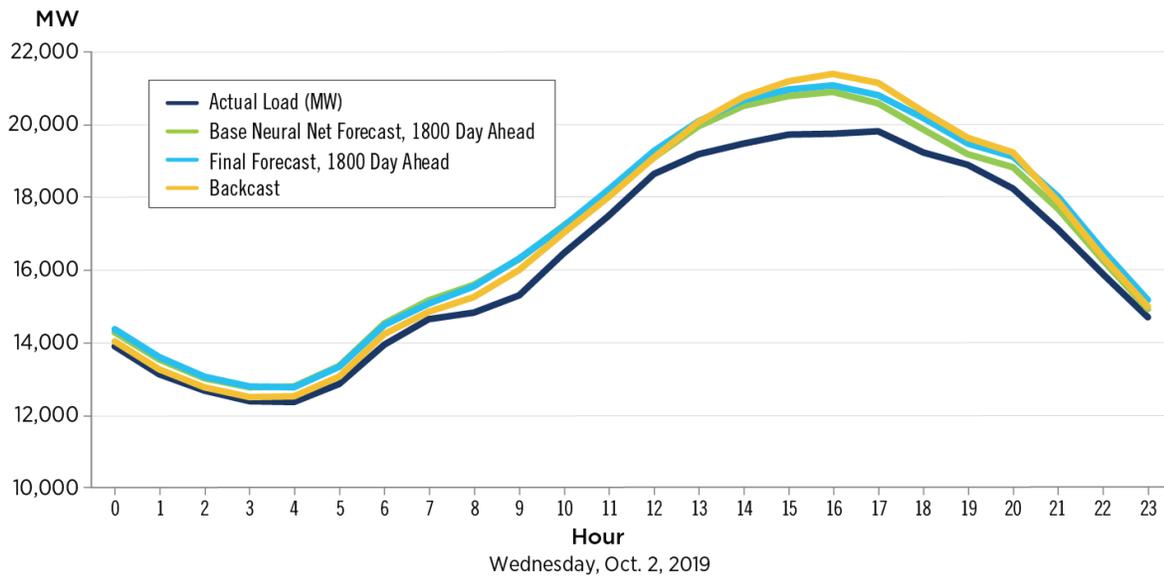
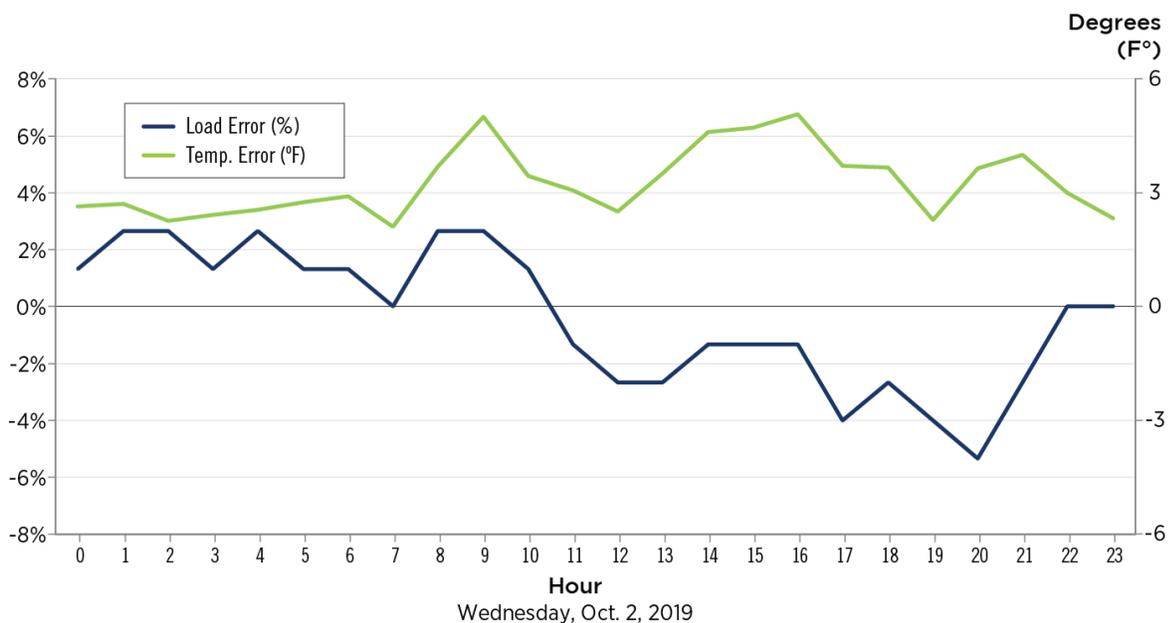


Figure 25. Results of AEP Temperature Error Analysis



Nodal Load Pattern Analysis

Methodology

While cold fronts that move across wide areas can impact load at a zonal level, some other drivers of load forecast error necessitate a more granular analysis. Demand response participants, behind-the-meter generation, and non-conforming load are not distributed evenly throughout each transmission zone, and each may contribute to unique load shapes at various nodes throughout the system. Load curves for telemetered nodal equipment were evaluated and classified into categories such as normal load behavior and intentional load reduction.

Results and Conclusions

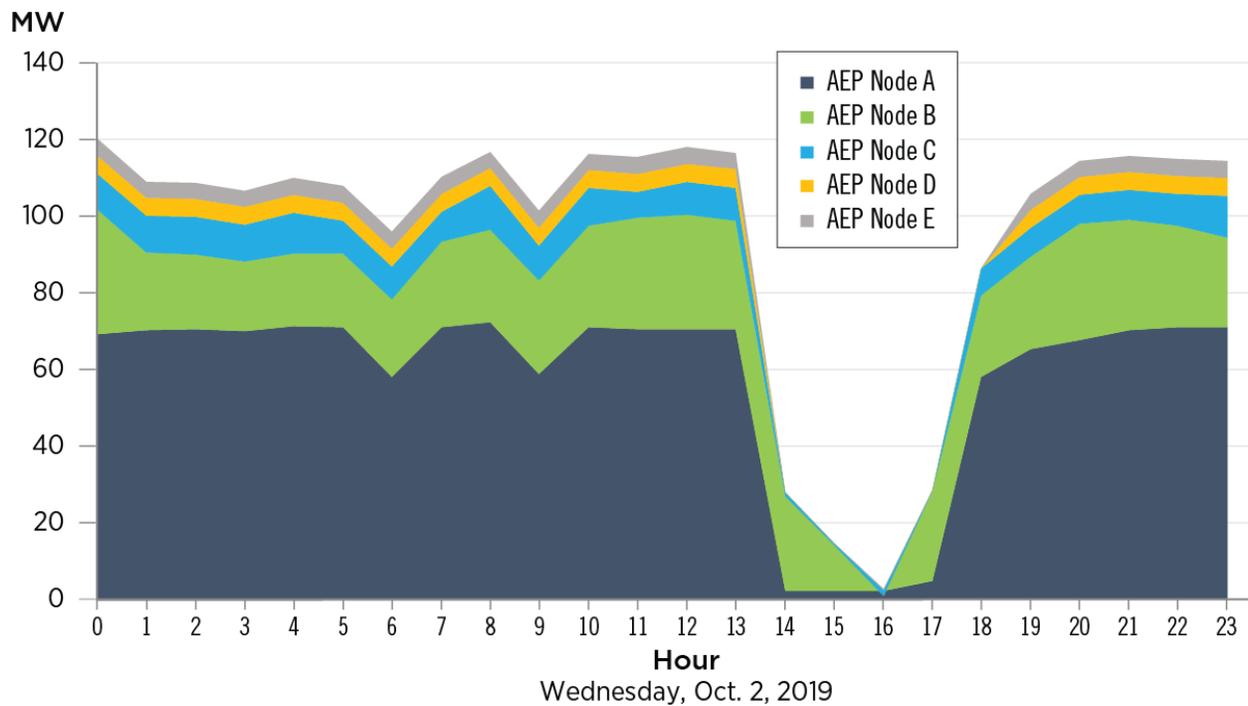
Load at many nodes throughout PJM was found to have decreased from 1–3 p.m., even though temperatures were rising. Many others increased but at a slower rate than the forecast would indicate. This behavior appears to be the primary cause of the error in AEP and PJM Mid-Atlantic, and a partial cause of the error in FE, in tandem with weather forecast error. The estimated 728 MW of PJM demand response will account for some of this reduction at some nodal equipment during the 2–4 p.m. timeframe. More work is needed to determine how much of the non-weather-driven load reduction during the PAI can be classified into the following categories: scheduled PJM DR; over-responsiveness of PJM DR; non-PJM, behind-the-meter load management programs; and industrial load response.

Case Study: AEP Nodal Load Reductions

While the load reduction in AEP cannot be explained by temperature, several instances of reduced load have been observed at nodal equipment. As shown in Figure 26, five nodal loads account for over 100 MW of load reduction. Many others decreased by smaller amounts.

The backcast estimated a 1,674 MW increase in load in AEP from hour ending 1–3 p.m.. An 831 MW increase was actually observed, leaving 843 MW of “missing load.” 450 MW of demand response was dispatched in AEP, leaving almost 400 MW unaccounted for and potentially attributable to load management programs that are not visible to PJM. A similar calculation for the PJM Mid-Atlantic zone, the other area whose error was not driven by weather, yields nearly 1,200 MW. A thorough analysis is needed to determine which nodal loads experienced decrease due to demand response compared to other reasons.

Figure 26. Example of Nodal Load Behavior in AEP



Conclusions and Recommendations

While PJM's review has resulted in some initial observations and recommendation areas, PJM will work with stakeholders to prioritize recommendations for further development. Some of these areas include the need to:

- Develop tools or approaches to increase observation of distributed energy resources and load during operational events. This will include working with states and members to gather additional data. These may also include developing additional tools to forecast this behavior in PJM operational tools.
- Review triggers for capacity performance and demand response triggers to ensure they are effectively triggering the reliability signals for which they were designed.
- Review load and weather forecasting tools to ensure they adequately include the data needed to provide accurate forecasts to operators and stakeholders.
- Review procedures for deployment of DR in entire zones as opposed to more granularly given the specific transmission constraints with which we were concerned.
- Work with stakeholders regarding any rule changes deemed appropriate based on the above analysis.
- Minimize or eliminate instances where emergency actions are taken triggering a PAI in locations where additional resource response is not needed as signified by low or negative prices. Clarify guidance to generators subject to performance assessments at locations where prices are low or negative during a PAI.

PJM will be presenting this paper to its Operating Committee and in other forums and looks forward to continuing to work with stakeholders to analyze the events of Oct. 1 and 2.