2016 Winter Report

May 31, 2016

PJM Interconnection

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Executive Summary

System performance during winter 2015-16 was excellent. PJM Interconnection experienced a mild winter season, which drove down normal winter loads. November and December were warmer than usual; January and February temperatures were normal.

Temperatures and Peaks

PJM experienced a milder winter than the previous two winters in terms of temperatures and peak load. The previous winters had extremely cold temperatures for long periods. December 2015 temperatures were above average making the month the warmest on record for the entire eastern U.S. January 2016 was much closer to normal on average but had both warmer and colder than normal weather periods. With the strong *El Niño*, the preseason forecast was for a warmer-than-average season as a whole with some periods of colder weather, however none as severe as February 2015.

During the 2015-16 winter peak hour Jan. 19, 2016, hour ending 0800, lows ranged from near zero degrees in Chicago to around 20 degrees in Norfolk. The RTO average low temperature was 8 degrees from 0600 to 0900. The RTO average high temperature was 20 degrees.

Generator Performance

Forced outage rates for January and February 2016 averaged 4.0 percent. In contrast, average forced outage rates for the same time period in 2015 and 2014 were 6.5 percent and 10.05 percent, respectively. During the winter peak, the forced outage rate was 5.1 percent, lower than historical norm of about 7 percent.

Performance improvements initiated after winter 2013-14 continued with testing efforts for dual-fuel and infrequently run units. Before winter 2015-16, 137 units totaling 10,141 MW (13,617 MW Installed Capacity) performed the cold weather generation exercise. Total cold weather testing make-whole cost totaled about $3.4 million.

Operations

Accurate forecasting is important for planning and preparing for daily operations and is the primary driver for scheduling generation. The average load-forecasting error for the Jan. 19, 2016, peak was 1.64 percent, slightly better than the daily average of 1.77 percent.

PJM met the Jan. 19, 2016, peak without the need for emergency demand response, shortage pricing, emergency energy purchases or emergency procedures beyond a cold weather alert. PJM also maintained its reserve requirements at all times.

Gas/Electric Coordination

PJM continued to build on the gas-electric coordination efforts established after the 2014 Polar Vortex. The Gas Electric Coordination Team continued to hone and improve generator risk assessment tools and reports to assist with dispatching efforts. The team also ramped up communication protocol and informational sharing with interstate pipelines as well as critical Local Distribution Companies across the PJM footprint. In general, winter 2015-16 presented much less challenge from a gas-supply perspective than the prior two winters due to the warmer-than-normal conditions and, thus, a greater level of pipeline capacity availability

Impact on Market Operations

The average Locational Marginal Price this winter was $69.82 per megawatt-hour. The RTO real-time LMP hit a high of $179.39, Jan. 18, 2016, hour ending 1900. PJM's 2016 winter peak was 130,680 MW on Jan. 19, 2016, hour ending 0800 when LMP was $69.82. The misalignment between high LMP and peak load indicates that PJM did not experience extreme conditions or system constraints during this period and capacity was readily available. By comparison, the highest RTO real-time LMP, due to the record-setting winter peak on the morning of Feb. 20, 2015, hour beginning 0600, was $418.67 MWh. During the Polar Vortex, Jan. 7, 2014, LMPs exceeded $1,800 per megawatt-hour.

Uplift moderated in January and February 2016 compared to the same period in 2015. Uplift for January and February 2016 combined was $28.67 million, compared to $150.5 million for the same period in 2015.

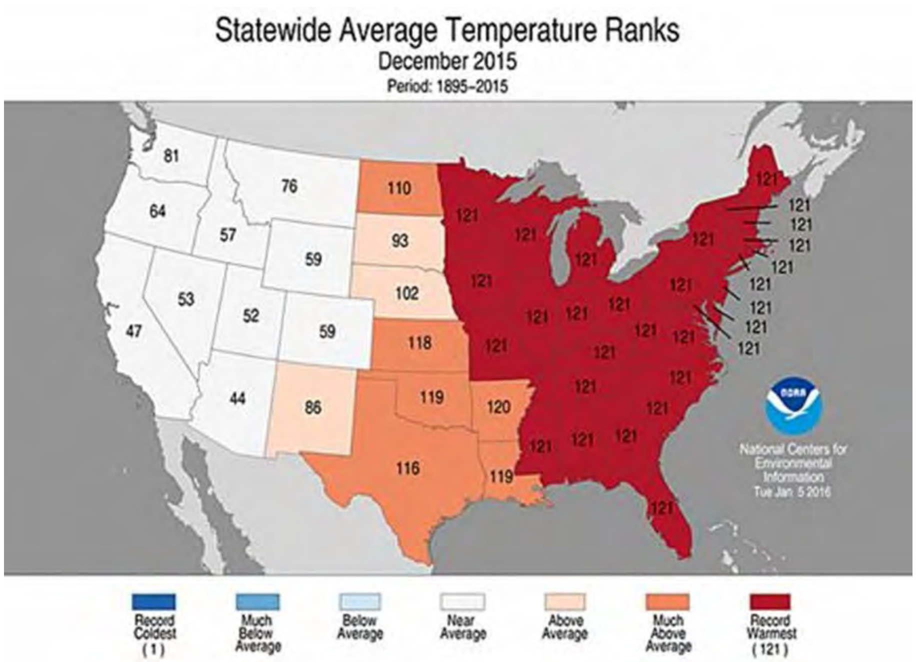
Report Organization

This report is organized by key topic, including Weather and Load, Generator Performance, Natural Gas Conditions, Market Outcomes, Emergency Procedures, Reserves, Interchange and Bulk Electric System Status, followed by a summary of implemented 2015 recommendations and their impacts.

Weather and Load

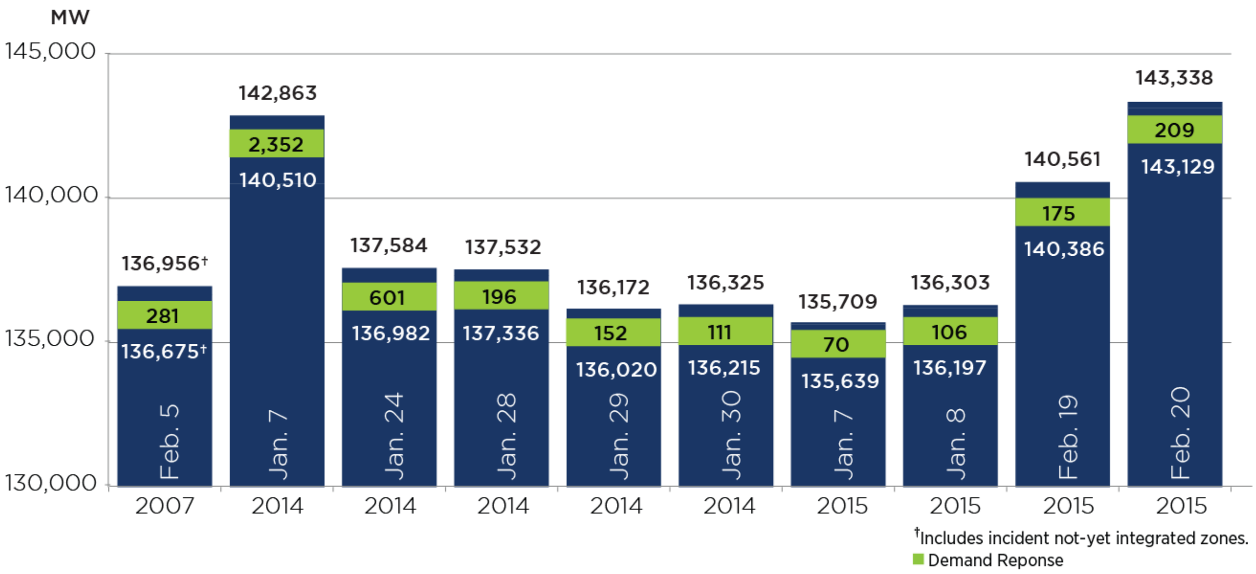
PJM Interconnection experienced a mild winter of 2015-16 unlike the previous two winters with extremely cold temperatures for long periods. December 2015 temperatures were above average, making December 2015 the warmest on record for the entire eastern U.S. January 2016 was much closer to normal, on average, but had periods of both warmer and colder than normal weather. With the strong *El Niño* in place, the preseason forecast was for a warmer-than-average season as a whole with some periods of colder weather, however none as severe as February 2015.

During the 2015-16 winter peak hour Jan. 19, 2016, hour ending 0800, lows ranged from near zero degrees in Chicago to around 20 degrees in Norfolk. The RTO average low temperature was 8 degrees from 0600 to 0900. The RTO average high temperature was 20 degrees.



The PJM 2015-16 winter peak demand was 130,680 MW compared to the all-time winter peak demand record of 143,086 MW set Feb. 20, 2015, hour ending 0800, when there were lower temperatures and associated high-electricity demand for heating needs.

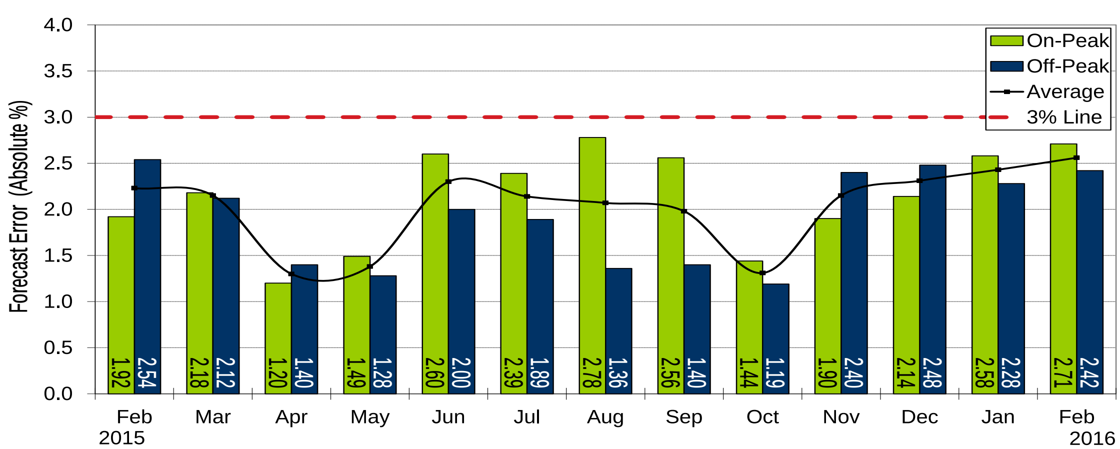
Figure 1. Top Ten RTO Winter Peaks



Load Forecasting

Load forecasting and the accuracy of the forecast are critical to PJM operations. The forecast load is the basis for generation scheduling decisions. Any error, high or low, can significantly impact both reliability and prices. PJM's goal is to forecast load with an error rate of less than 3 percent. The average load forecast error for the 2016 winter peak day was 1.77 percent.

Figure 2. Load Forecasting Error Chart



PJM uses a neural net load forecasting model, which uses historical data, including "similar load day" and "similar weather day" to develop the forecast. To develop the published forecast, a PJM dispatcher and an on-staff meteorologist review the forecast and make adjustments based on experience and system conditions. This process begins a week before an operating day and continues until the operating day. During that time, PJM monitors weather projections and historical load patterns to update the published load forecast, sometimes multiple times per day.

2016 Generator Performance

Overall there was a large reduction in forced/unplanned outages between the winter 2014-15 and winter 2015-16 peaks. To better understand the impact of improvement efforts, PJM reviewed the online generation and outage amounts and causes.

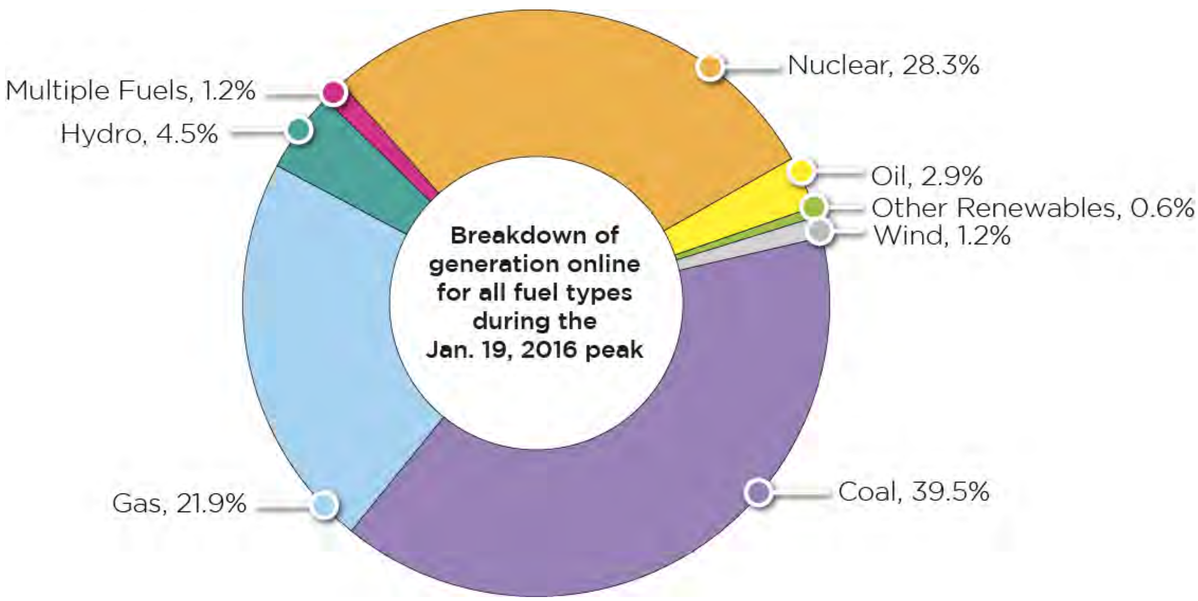
Generation Online

PJM reliably met the peak load and maintained reserve requirements in winter of 2015-16 without activating emergency demand response resources, using market mechanisms (such as shortage pricing), purchasing emergency energy or calling for emergency procedures beyond cold weather alerts. Due to unit retirements, installed generation decreased a net 6,412 MW in from 2015. Improved generator performance was a key contributing factor to this outcome.

The following amount of generation was online in the PJM footprint during the 2016 winter peak Jan. 19, 2016.

Date/Time	Installed Generation (MW)	Generation Online (MW)
01/19/2016 08:00:00	179,050	125,851

Figure 3. Breakdown of generation online for all fuel types during the Jan. 19, 2016, peak

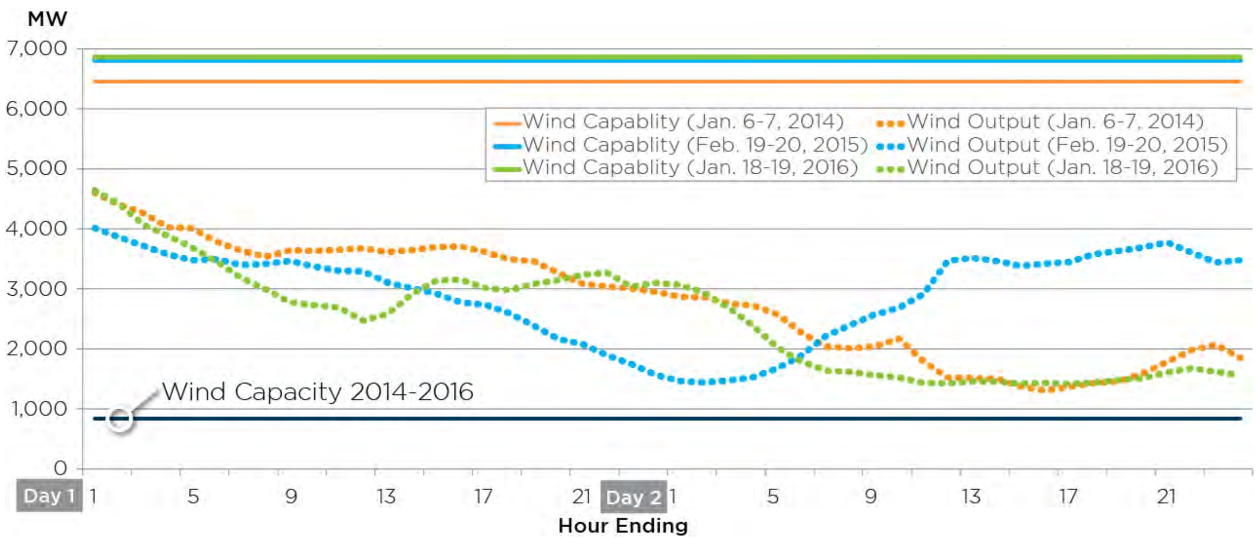


This generation mix is similar to the generation mix that was online during the peak in Feb. 20, 2015.

Performance of Wind Units

The chart below shows the trending wind generation output during the Jan. 7, 2014, Feb. 20, 2015, and Jan. 19, 2016, peaks compared to the total capability and capacity of the wind generation resources in PJM. (Note that currently in PJM the average wind capacity factor is 13 percent of total wind capability.) Wind production over the winter peak hour in 2015 (Feb. 20, hour ending 0800) was approximately 2,575 MW out of a total capability of 6,811 MW (capacity factor of 38 percent). Wind production over the winter peak hour in 2016 (Jan. 19, hour ending 0800) was approximately 1,562 MW out of a total capability of 6,863 MW (capacity factor of 23 percent).

Figure 4. Wind Generation Performance at Peaks (2014 through 2016)



Performance of Retiring Generation

Environmental regulations will have resulted in approximately 14,000 MW of generation retiring between 2015 and 2018. Until the units retire, they still are available for PJM to dispatch to meet load. The table below indicates how the units scheduled to retire performed during the winter peaks of 2014, 2015 and 2016.

Figure 5. Retiring Generation during the winter peaks of 2014, 2015 and 2016

Retiring Generation	Jan. 7, 2014 19:00	Feb. 20, 2015 08:00	Jan. 19, 2016 08:00
Installed Capacity (MW)	14,036	11,560	2,576
Generation Online	7,273 (52%)	5,655 (49%)	1,152 (45%)
Total Outages (Planned, Maintenance, Forced)	5,333 (38%)	3,549 (31%)	194 (8%)
Forced Outages	5,222 (37%)	3,496 (30%)	27 (1%)
Not Called	1,041 (7%)	1,971 (17%)	999 (54%)

The forced outage rates for retiring units in 2016 were not as high as the forced outage rate for retiring units in 2014 and 2015, but the pool of retiring resources also was reduced by unit retirements in previous years.

Generator Outages

The biggest difference in generator performance between winter 2015 and winter 2016 was a reduction in generator forced outages. Outages can be planned[1], maintenance[2], or unplanned[3]. Unplanned, or forced, generator outages challenge grid reliability and are the most difficult to manage in real-time operations.

The chart shows the trending of forced, maintenance and planned[4] outages during January and February 2016. As indicated in the chart, forced/unplanned outages are responsible for a large portion of the generator unavailability.

Figure 6. Forced Outage Peaks: January – February 2016

During the 2016 winter peak on Jan, 19, 2016, the forced outage rate was 5.1 percent as compared to the forced outage rate of 12.6 percent during the all-time winter peak Feb. 20, 2015. Another way to look at generator performance is by the number of hours during which forced outages were equal to or greater than 10 percent of the installed generation. The historical average winter outage rate is 7 percent. Using 10 percent as a threshold is a statistically significant amount above the historical average. The table below shows the hours for January and February in 2014, 2015 and 2016 when forced outages were equal to or greater than 10 percent of the installed generation, as well as the average forced outage rates.

[1] Planned Outage - The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with approval of PJM. Planned outages may last for several weeks and usually occur only once or twice per year.

[2] Maintenance Outage - The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility with approval of PJM. Maintenance outages may be deferred beyond the next weekend and are typically much shorter than planned outages.

[3] Unplanned/Forced Outage - An immediate reduction in output or capacity or removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility.

[4] Training on forced, maintenance, and planned outages can be found in the 2014 Winter Webinar Training http://www.pjm.com/~/media/training/webex-documents/winter-weather-procedure-changes.ashx

Figure 7. Number of hours during January and February when forced outages were equal or greater than 10 percent of the installed generation

	2014	2015	2016
Number of Hours >=10% Forced Outage Rate	639	159	0 (Max 7.5%)
Average Forced Outage Rate (Jan-Feb)	10.05%	6.5%	4.0%

Also, shown below are the total outage rate (sum of forced, maintenance and planned outages expressed as percent of installed generation) comparisons between 2014, 2015 and 2016.

Figure 8. Total Outage Rate

Forced Outage Causes

Generators are required to submit forced outage data after the outage has occurred. From this data, PJM can analyze and understand the cause of the outage, as designated by the unit owner. Generators did not have as many problems in 2016, unlike 2014 and 2015 when extreme conditions challenged all conventional forms of generation, including natural gas, coal and nuclear.

The charts below break down forced outages by generator primary fuel at the winter peaks for 2016, 2015 and 2014.

Figure 9. Outage by Primary Fuel Jan. 19, 2016

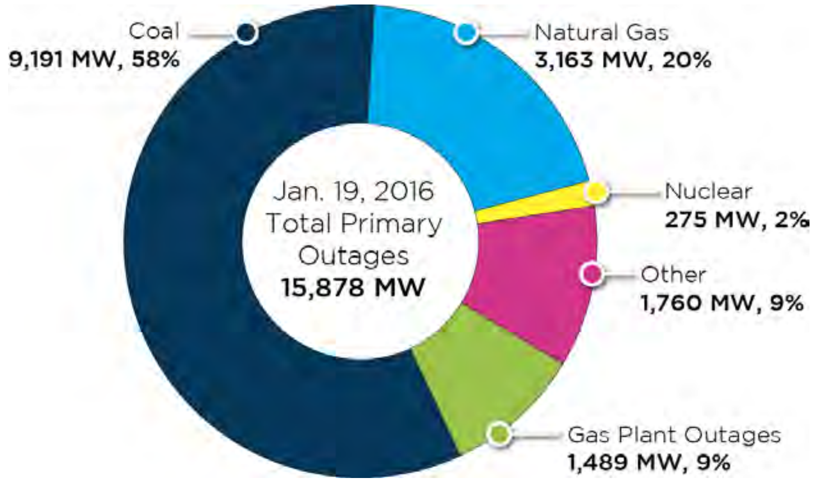


Figure 10. Outages by Primary Fuel Feb. 20, 2015

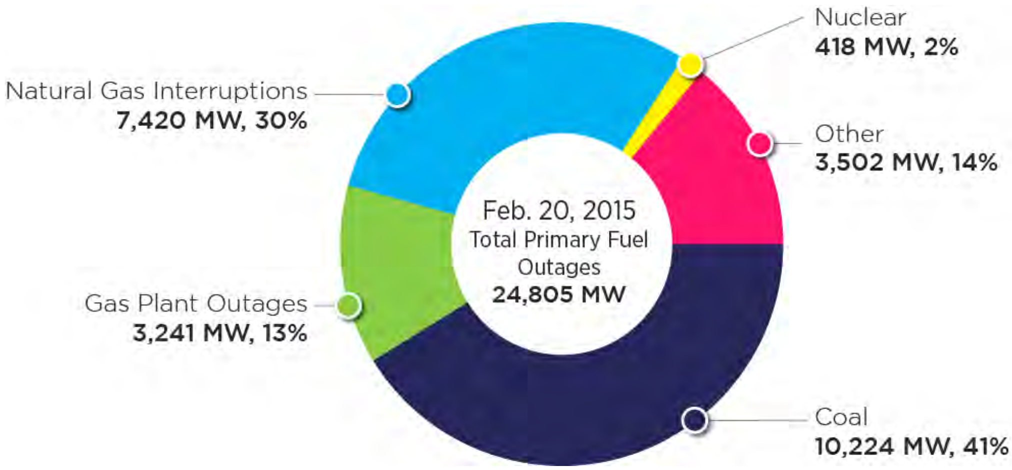
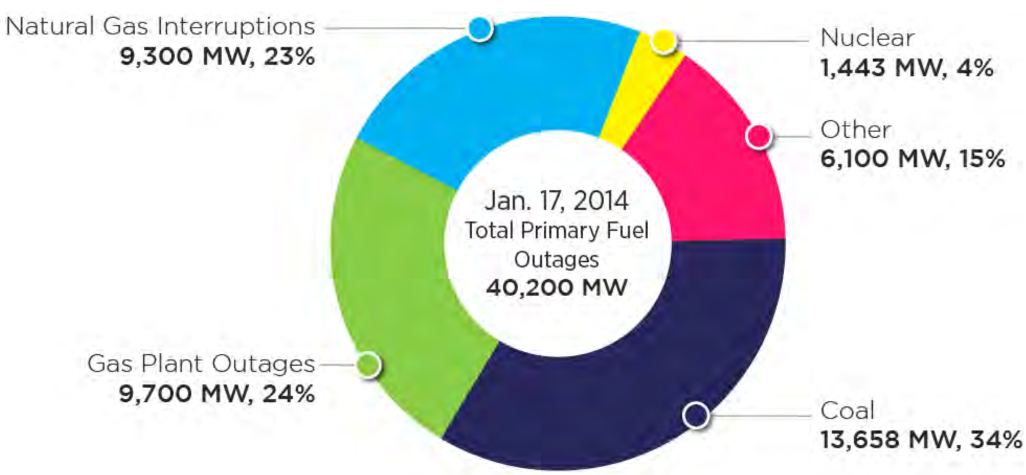


Figure 11. Outages by Primary Fuel Jan. 7, 2014



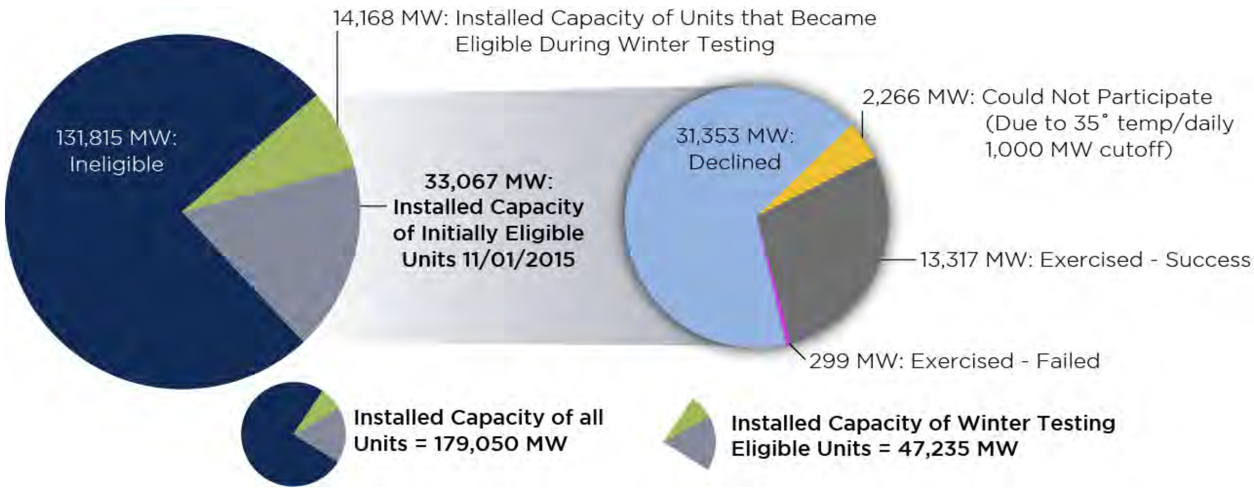
Note: "Other" includes heavy oil, kerosene, landfill gas, light oil, waste, water, wood, ambient corrections, wind, solar and batteries.

Cold Weather Operational Exercise

PJM also implemented the 2014 recommendation to develop a cold weather exercise to give generators that run infrequently or have dual-fuel capability the opportunity to test their units before the onset of cold weather. The goal of the testing is to identify and resolve startup, operational and fuel-switching issues to improve unit reliability during peak periods.

Generation resource owners could voluntarily exercise some of their generation resources to determine their readiness to respond to PJM's dispatch instructions in cold weather. Generation resource owners were compensated based on the cost-based schedule for the identified fuel type. Alternatively, a generation resource owner could elect to self-schedule a resource to validate its cold weather operation.

Figure 12. Cold Weather Resource Operational Exercise ICAP by Category



In total, 137 units with a combined 10,141 MW (13,617 MW ICAP) performed the cold weather generation operational exercise this winter. The total cost of these tests was $3,357,549.32. In 2014, 168 units with a combined capacity of 9,919 MW (11,054 MW ICAP) performed the cold weather generation operational exercise. The total cost of these tests was approximately $4,883,000.

Cold Weather Resource Preparation Checklist

PJM also implemented a cold weather generation checklist program in the fall of 2014, which required resource owners to confirm the completion of the PJM checklist in Manual M14D or an equivalent tool developed and maintained by the generation resource owner. This program was to increase awareness of winter preparedness and provide generators a guide to reduce and eliminate similar problems experienced during the 2014 cold weather events. Generation resource owners were to review their plant designs and configurations, identify areas with potential exposure to the elements, ambient temperatures or both, and tailor their plans to address them accordingly.

The response level across the PJM footprint on the cold weather generation checklist continues to be very good. Approximately 94 percent of all generation resources confirmed completion of either the PJM checklist or their equivalent, an increase from 91 percent in 2014.

Natural Gas Conditions 2016

As highlighted in the Generator Performance 2016 and Reserves sections of the report, there were 9,992 MW of forced outages at the peak Jan. 19, 2016. Approximately 3,163 MW (25 percent) resulted from natural gas interruptions. By comparison, in 2015 there were 7,420 MW of forced outages at the peak Feb. 20, 2015, resulting from natural gas interruptions. PJM reviewed the availability of gas and gas restrictions issued in the PJM footprint, as well as the price of natural gas and heating oil.

Natural Gas and Liquid Natural Gas Availability and Storage

Record warmth dominated winter 2015-16 across the PJM footprint resulting in less gas deliverability issues compared to the previous two winters. Supplies of natural gas and heating oil were abundant, and prices for both commodities reached near record low levels during the winter. U.S. natural gas storage inventory was well above the last two winters and the five-year average levels.

There were occasional, but manageable, gas pipeline restrictions that impacted supply to gas generation. These restrictions primarily occurred during the President's Day holiday weekend of and were most evident within the Baltimore and New Jersey local distribution companies markets where generators were being interrupted due to capacity reductions impacting the local gas distribution systems.

PJM Gas-Electric Coordination Team

PJM continued gas-electric coordination efforts, as recommended in the 2015 Winter Report. Increased coordination with interstate natural gas pipelines has assisted with providing a greater understanding of real-time gas transmission operational constraints and longer-term maintenance and construction activities potentially impacting gas-fired generation. In addition to the increased cooperation with the interstate pipelines, the PJM Gas Electric Coordination Team ramped up outreach to LDCs to develop a comprehensive communication and coordination effort. This outreach was concentrated at first on those LDCs with the greatest amount of natural gas-fired generation behind their city gates and those that typically have been the most constrained over the past several winters.

2016 Market Outcomes

LMPs and ancillary service market clearing prices MCP reflected systems conditions throughout the duration of the winter. Moderate LMPs and MCPs during the winter months were driven by warm temperatures, moderate load, low gas prices and the lack of major transmission constraints. Larger LMPs occurred close to the winter peak period. The highest LMP for January-February 2016 was $179.39 Jan. 18, 2016, hour ending 1900. In only 12 hours in January-February 2016 were LMPs over $100 in real time, which occurred during morning or evening pick-ups. No day-ahead LMPs were over $100.

Locational Marginal Pricing

LMPs are determined based on the cost to provide the next increment of energy while respecting the primary and synchronized reserve requirements, congestion and marginal losses. PJM's real-time dispatch and LMP calculation systems jointly optimize energy, reserves and regulation to ensure that all system requirements are met using the least cost resource set. This construct allows accurate reflection of price signals with a higher degree of consistency between ancillary services and prevailing energy prices.

The chart below shows the real-time and day-ahead energy prices Jan. 19, 2016.

Figure 13. Locational Marginal Pricing Jan. 19, 2016

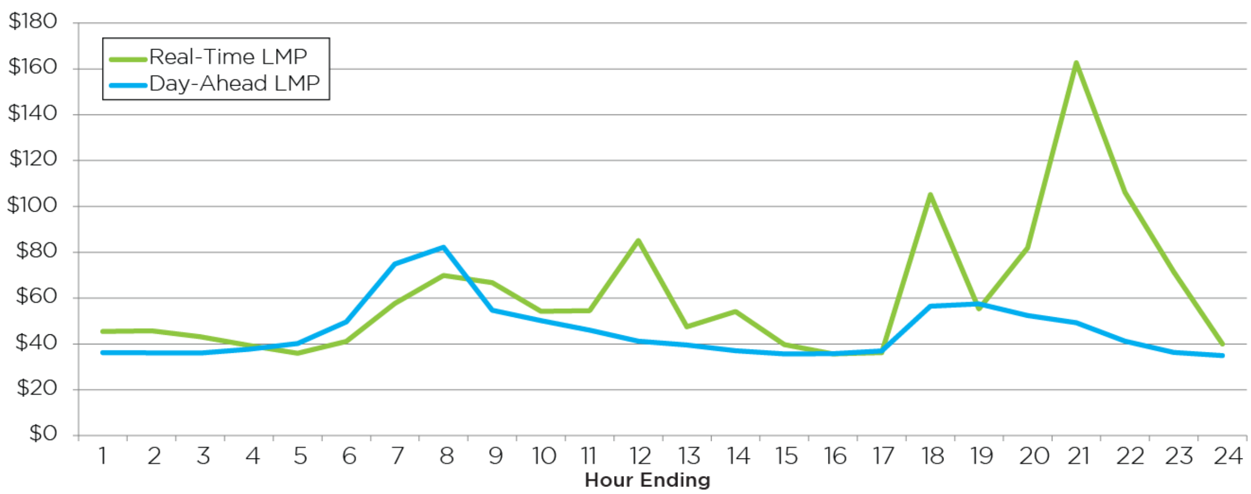
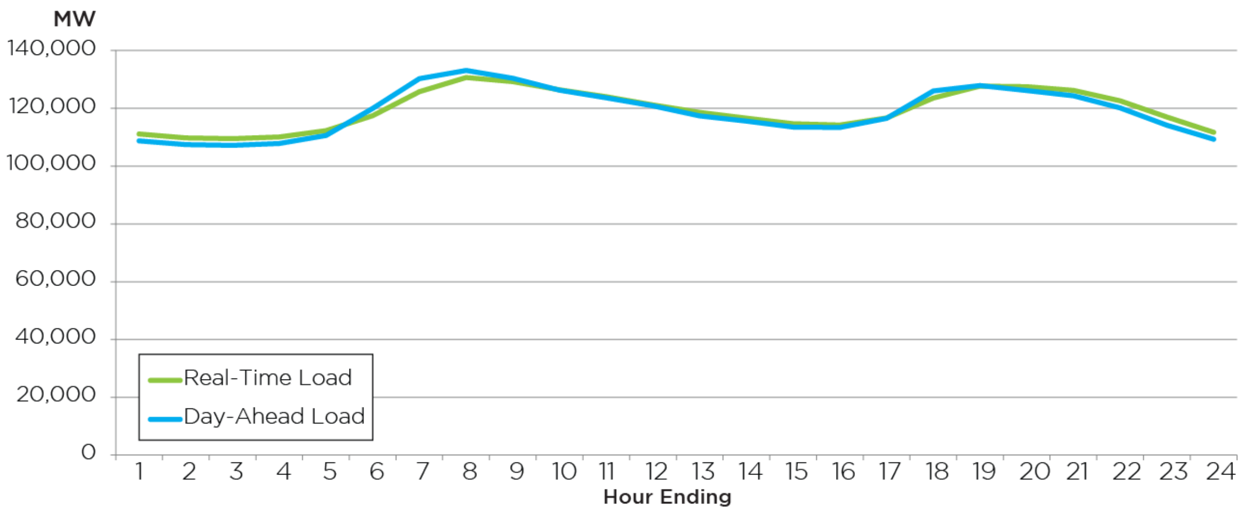


Figure 14. Day-Ahead versus Real-Time Megawatt Jan. 19, 2016

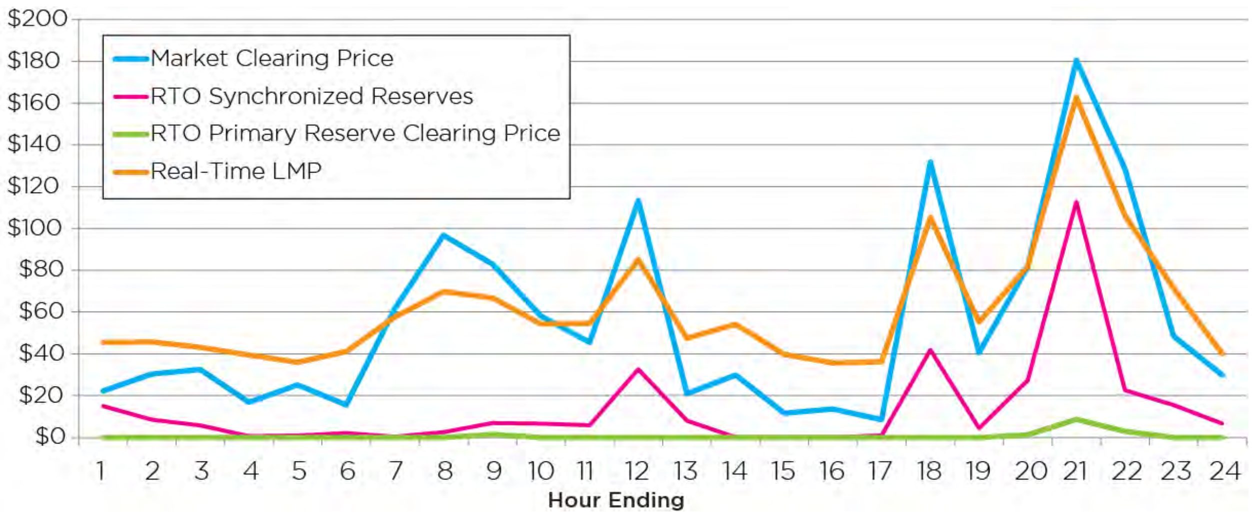


Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserve

During the January 2016 peak, prices for regulation, synchronized and non-synchronized reserves occurred around the same time as the real-time energy LMP peak. The simultaneous pricing of these products with energy leads to a harmonized set of prices that reflect actual system conditions.

PJM implemented regulation changes Dec. 14, 2015, as a result of the Regulation Performance Impacts group. Changes included an update to the regulation benefits factor curve, defined excursion hours for more conservative Regulation D procurement and the implementation of "tie-breaker" logic for zero-cost resources. Initial evaluation of these changes shows similar regulation procurement with the exception of the excursion hours when more Regulation A resources are being committed. Performance has been improved marginally since these changes with the biggest improvement in the excursion hours. These changes are temporary solutions to the ongoing, longer-term Regulation Market Issues Senior Task Force efforts.

Figure 15. January 2016 Ancillary Service Price and Energy Price

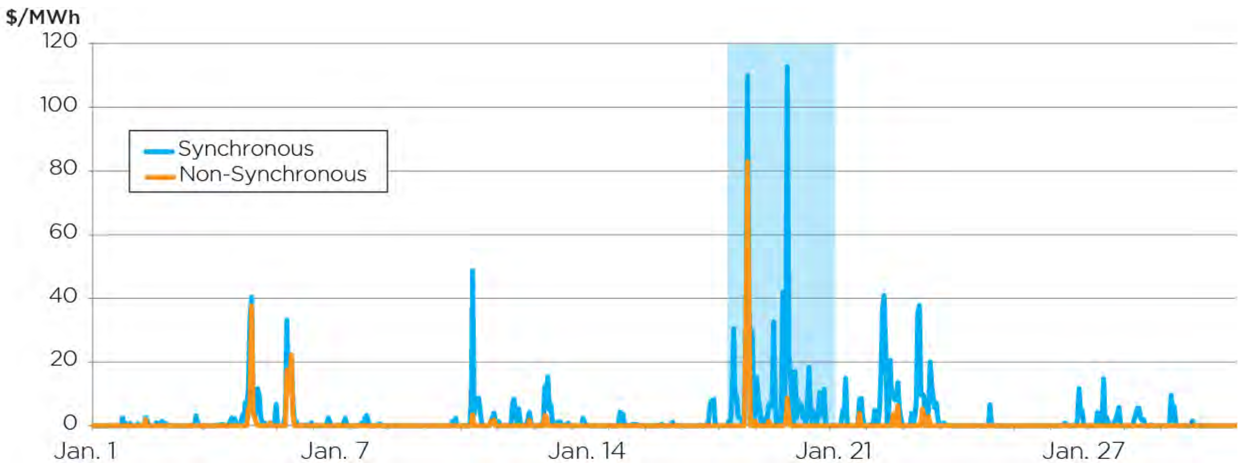


The winter peak load Jan. 19, 2016, hour ending 0800, did not bring peak ancillary service or energy prices. Ancillary service prices were in line with the energy prices, no large price spikes. Prices were moderate, no anomalies or large price spikes.

Reserves Pricing

Reserve market clearing prices trended with energy prices during winter 2015-16 without any unanticipated excursions. Both synchronized and non-synchronized reserves had relatively small spikes in prices and volatility during the Jan. 19, 2016, winter peak. The maximum synchronized reserve prices occurred around the winter peak. The maximum synchronize reserve clearing price of $112.71 was Jan. 19, 2016, Hour Ending 2000, coinciding with rising real-time energy prices. The rising energy prices resulted from high loads and a reserve event during this hour. Reserve events typically produce higher energy prices due to the short-term need for more energy on the system.

Figure 16. Synchronous and Non-Synchronous Reserve Prices



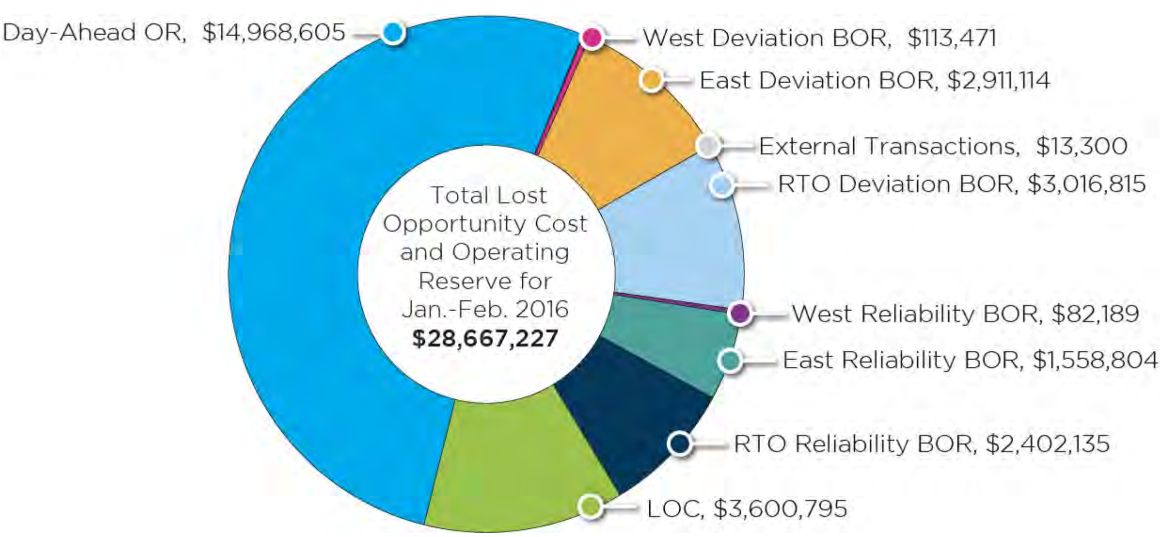
During peak, there was a relatively small peak in reserve pricing. Peak pricing occurred around the 2016 winter peak when prices were the highest in the evening periods January 18 and January 19, coinciding with higher LMPs at the time. In comparison, the peak reserve pricing for 2015 was >$200.

Uplift

To incent generators and demand response resources to operate as requested by PJM, resources that are scheduled by PJM and follow the company's dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources which follow PJM's direction.

Operating reserve costs, the primary form of uplift in PJM, are payments made to economic demand resources and generation resources, which follow PJM's direction, to cover their costs. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to market participants.

Figure 17. Total Lost Opportunity Cost and Operating Reserve January/February 2016



Lost Opportunity Costs were comparable for winters 2015 and 2016, both around $31 million. Operating Reserves costs were measurably lower in comparison. Total LOC/BOR for 2016 was $56 million, about one-third of the amount in 2015.

Uplift is an important feature in the PJM Energy Market design due to the number of variables associated with dispatching the system and maintaining control. While there is a trade-off between lower energy prices and uplift because, generally, as uplift is reduced, energy prices will rise, and vice versa. No solution eliminates uplift completely. Through the Energy Market Uplift Senior Task Force, PJM and its stakeholders have made progress to provide solutions to reduce uplift. The task force has focused on uplift credit methodology and specific units parameters that would enable the reduction of uplift.

From Jan. 1, 2016, through March 31, 2016, PJM received seven cost-based energy offers that were greater or equal to $1,000/MWh. None of the offers received were accepted because system conditions did not warrant running those units.

Emergency Procedures

PJM did not need any emergency actions during winter 2015-16. At the highest peak periods, PJM only needed to issue alerts and warnings, which are designed to increase awareness and readiness for weather conditions. A cold weather alert was the most-frequently issued emergency procedure during January and February. PJM issues a cold weather alert in advance of an actual operating day when forecasted temperatures are 10 degrees Fahrenheit or lower, so market participants can prepare for the extreme weather conditions.

There were four cold weather alerts[5] in 2016 versus 21 in 2015. No additional emergency procedures were used in the winter 2016. PJM was in a cold weather alert for 92 hours total during winter 2015-16 (46 hours in January 2016 and 46 hours in February 2016). In comparison, PJM was in a cold weather alert for 504 hours total during winter 2014-15.

Reserves

PJM maintains sufficient reserves to handle unexpected conditions on the system. Reserves are defined as capacity that is not currently being used but that can be available quickly for an unexpected loss of generation or a grid contingency. To ensure the reliable operation of the grid, as well as to comply with North American Electric Reliability Corporation, ReliabilityFirst and SERC Reliability Corporation standards, PJM established a primary (contingency) reserve requirement[6] and a synchronized reserve requirement[7] as further detailed in PJM Manual 13 -

[5] This total includes alerts called for the entire RTO and separate regions in the RTO

[6]The Primary Reserve Requirement is capability, consisting of synchronized and non-synchronized resources, which can be converted fully into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 150 percent of the largest single contingency in the RTO.

[7] The Synchronized Reserve Requirement is capability, comprised only of synchronized resources, which can be fully converted into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 100 percent% of the largest single contingency in the RTO.

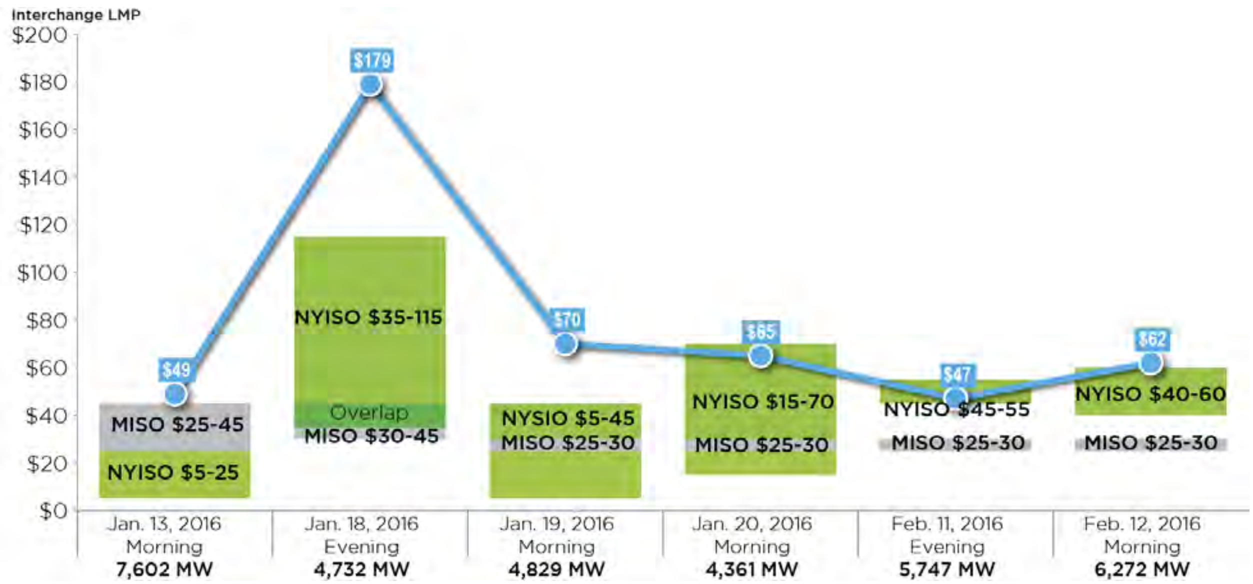
Emergency Operations. If the reserve requirements are not met, PJM may implement emergency procedures and shortage pricing, as indicated in PJM Manual 11 - Energy & Ancillary Services Market Operations.

During the winter of 2015-16, PJM maintained the primary (contingency) and synchronized reserves estimates above NERC/RF/SERC requirements at all times. Unlike winter 2013-14 but similar to winter 2014-15, no emergency procedures were required.

Interchange

Managing interchange (energy transfers across the RTO) was not operationally challenging on the peak winter days in 2016. Interchange for the peak days of January and February are reviewed below.

Figure 18. LMP Interchange for Peak Days of January and February 2015



Interchange in-line with PJM LMP compared with MISO and NY. PJM received the most imports when LMPs were at their highest and measurably larger then NY and MISO.

Bulk Electric System Status – Transmission

PJM prepared for winter 2015-16 peak operations by analyzing winter transmission outage requests to understand impacts to reliability and congestion. The PJM Peak Period Outage Scheduling Guidelines indicate transmission owners should avoid scheduling transmission outages that may result in increased risk to system reliability during the winter peak periods.[8]

Before approving outages that transmission owners needed to schedule over the 2016 winter peak, PJM analyzed each outage request in detail – under winter peak system conditions – to ensure system reliability could be maintained. The detailed analysis included an assessment of congestion impacts. If there were a significant

[8] Manual 3: Transmission Operations, Section 4: Reportable Transmission Facility Outages, 4.2.6 Peak Period Outage Scheduling Guidelines

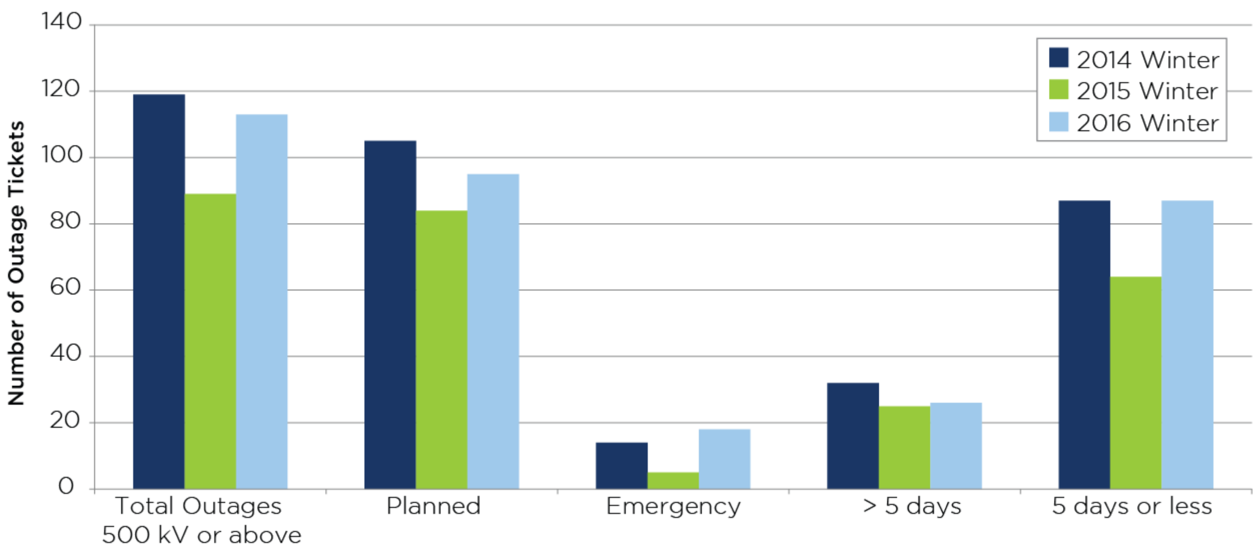
congestion impact for the outage – considering factors such as the amount of off-cost operations and number of units and megawatts impacted, PJM suggested that the outage be rescheduled. PJM also communicated to PJM members through the PJM committee process about long-duration 500 kV or above transmission outages (e.g., those scheduled for the entire season) and projected impacts.

Key Transmission Outages in 2016: Planned and Unexpected Outages

The transmission outage with the largest operational impact during winter 2015-16 was the Cloverdale – Lexington 500 kV line, which was removed from service Jan. 4, 2016, for scheduled work. AEP was reconductoring its portion of the line under RTEP project b1797.1. The line has a June 30, 2016, estimated return-to-service date.

As a result of this outage, south-north flows increased from Duke Energy Progress into PJM causing congestion during higher load periods. PJM initiated unit re-dispatch and curtailed transactions under the Transmission Loading Relief process to mitigate post-contingency exceedances on the Person – Halifax 230 kV tie line for the loss of Wake – Brunswick Switching Station 500 kV tie line.

Figure 19. Winter Peak 500 kV or Above Transmission Outage Comparison for January and February 2014, 2015 & 2016



The following projects were implemented in time for winter 2015-16 season and would have been helpful if PJM had experienced higher system loads such as those experienced during the past two winter seasons:

- Two new 230 kV lines in the PSE&G North system: Bergen – Athenia A-2332 and Athenia – Saddlebrook F-2337 lines
- Two transmission projects designed to support the retirement of Shawville generation: installations of the Mainesburg 345/115 kV substation and the Squab Hollow 230/138 kV substation and SVC (providing a dynamic reactive resource for the area).
- Two transmission projects designed to support the retirement of Sporn and Muskingum River generation: the Sporn – Waterford – Muskingum River 345 kV line and the Sporn – Kyger Creek 345 kV tie line.

- Various 500 kV and 230 kV projects in Dominion's Chesapeake area were completed to support Chesapeake generation retirements. These included:
    - Installing six 500 kV breakers at Yadkin to accommodate the new Septa – Fentress 500 kV line.
    - Installing a second 230/115 kV transformer at Yadkin.
    - Installing a third 500/230 kV transformer at Yadkin.
    - Reconductoring the Suffolk – Thrasher 2110, 230 kV line for a 1,593 MVA Load Shedding rating.

Table: Status of 2015 Recommendations and Lessons Learned

The recommendations identified in 2016 are a continuation of some recommendations identified in 2015.

ID	Category	Recommendation	Status
1	Capacity Performance	Continue with the implementation of the Capacity Performance proposal to address resource performance incentives on a sustained basis.	Capacity Performance went live June 1, 2016. Tool and process enhancements to support Capacity Performance have been implemented. Internal and external training and communications have been completed with stakeholders to support implementation.
2	Gas / Electric Coordination	Continue to improve coordination between the gas and electric industries: 1. Based on the FERC's Final Rule in Docket No. RM14-2-000, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, implement changes to better align the scheduling processes. A consideration could be moving the times of the Day-Ahead Market. 2. Offer even more flexibility in changing unit offers during the electric day, as has been discussed in the Gas Unit Commitment Coordination working group. 3. Improve transparency of generation within gas local distribution companies.	• PJM changed the timing of the energy markets on Apr. 1, 2016, to better align with the gas day. • The intraday offer proposal was submitted to FERC on Jan. 8, 2016. • PJM has increased outreach to LDCs to establish more effective communication protocol to better understand issues impacting gas fired generation behind the LDC city gates. Anticipated completion third quarter of 2016.
3	Generator Operational Parameters	Continue to improve the ability for generators to communicate operational parameters to PJM. 1. Improve the ability for PJM tools (e.g. eDART, Markets Gateway, DMT) to better capture and log generator flexibility and unit status information for use in real-time operations as well as after-the-fact analysis. 2. Improve PJM processes (e.g. PLS exception process) to review and assess generator parameters, particularly when they may differ from financial or settlements parameters.	• Real-Time Values or ability to communicate current operational capabilities became effective June 1, 2016. Real-Time Values are entered in the Markets Gateway tool and communicated to PJM Dispatch. • As part of Capacity Performance, PJM and the IMM reviewed unit specific operation parameters for some CP resources for the 2016/2017 delivery year.

ID	Category	Recommendation	Status
4	Cold Weather Unit Preparation	Build upon the success of the cold weather unit exercise and preparation checklist to improve the value while balancing the costs. Consider: 1. Modifying the criteria for eligibility 2. Refining the testing conditions and timeframe	• There was a slight increase in participation of units that completed the checklist to 94% from 91% in 2014. • PJM made minor process changes to the cold weather testing exercise, based on 2015 lessons learned and will reevaluate through the stakeholder process continuation of exercise prior to winter 2016/2017. PJM did not make any criteria changes to the cold weather unit exercise prior to the winter; only minor process changes. PJM will reevaluate through the stakeholder process continuation of exercise prior to winter 2016/2017.
5	Energy Market Uplift Reduction	Continue to investigate methods and procedures for reducing the amount of uplift to be paid.	Through the existing Energy Market Uplift Senior Task Force, PJM and its stakeholders continue to work on solutions to reduce uplift.