Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events

May 8, 2014
PJM Interconnection

Contents

Executive Summary

January 2014 was an extremely challenging month for much of the U.S. energy industry, particularly the electricity and natural gas sectors. Power system operators, power producers and consumers – both within the PJM Interconnection[1] footprint and in surrounding regions – endured prolonged periods of bitterly cold temperatures that drove up energy use, increased uncertainty for grid operators and stressed available power supplies. Throughout January 2014, PJM experienced tight operational conditions and a significantly higher number of forced generator outages – compared to a more typical January – due to the extreme weather, mechanical problems and natural gas market inflexibility.

Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. Peak demand for electricity was 35,000 megawatts, or 25 percent, higher than typical January peaks– an amount approximately equivalent to the electricity demand of Chicago, Washington, D.C. and Baltimore combined. On some days, even the lowest hours of demand were 10,000 MW higher than typical winter peak demands of recent years.

Although PJM and its members successfully met the unprecedented demand, heavy electricity use for heating and high natural gas prices sharply drove up the costs of wholesale power. For example, January 2014 total net billings to PJM members were one-third of the entire year's total net billings in 2013.

The Polar Vortex

The January 6-8 Polar Vortex brought prolonged, deep cold to the entire PJM footprint and surrounding regions. PJM set a new wintertime peak demand record of 141,846 MW the evening of January 7 while dealing with higher than normal generation outages. During the peak demand hour, 22 percent of generation capacity – including coal, gas and nuclear – was out of service.

The generation forced outage rate was two to three times higher than the normal peak winter[2] outage rate of around 7 to 10 percent. Equipment issues associated with both coal and natural gas units caused the greatest proportion of forced outages. Natural gas interruptions comprised approximately 25 percent of the total outages.

Reserves were tight during the Polar Vortex. Synchronized Reserves (those supplied to the system from resources that are synchronized/connected to the grid and able to load within 10 minutes) were at their lowest point the morning of January 7. For a five-minute period, synchronized reserves were reduced to about 500 MW, compared to a 1,372 MW PJM requirement. These are not, however, the only reserves available to PJM. During that hour, PJM had an additional 1,167 MW of primary reserves (reserves available in 10 minutes but not synchronized / connected to the grid) for a total of 1,667 MW of ten-minute reserves at the lowest point of the hour.

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[1] PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The Operations function of PJM (overseeing the flow of electricity) resembles an air traffic controller – PJM neither owns nor flies the planes, but instead makes sure all the planes can get where they need to go without incident. PJM does not own the transmission wires or the generators, but it directs the operation of those resources to serve electricity consumers. The Market function of PJM can be compared to a stock exchange. PJM neither buys nor sells, but operates the markets in which parties can conduct transactions.

[2] Normal peak winter outages were defined by looking at most recent five years December through February forced outage rates.

Although reserves were low, several steps remained available to operators before electricity interruptions might have been necessary. For example, in the event of the loss of a very large generator or a spike in electricity demand on January 7, PJM could have implemented a temporary voltage reduction. A reduction in distribution system voltage, although unnoticeable to almost all consumers, can reduce the load by about 1,100-2,000 MW. In addition, PJM also has formal reserve sharing agreements with its neighbors (Northeast Power Coordinating Council and Virginia-Carolinas Reliability Agreement) that could have been called upon if needed.

Winter Storms

Following the Polar Vortex, a second series of winter storms and extremely cold weather hit the region January 17 through January 29. PJM used its experience from the Polar Vortex to prepare for operations during this second cold spell in preparing load forecasts and anticipating generator performance and outages.

In spite of this preparation, scheduling constraints in natural gas markets – combined with frigid weather across the region, very high power demand and the lack of alignment between natural gas and wholesale electricity markets – created extreme difficulty in scheduling natural gas-fired generation to meet demand.

Natural gas scheduling problems were the key contributor to operational challenges – and high operating reserve costs – during this second period of cold weather. For example, to ensure that gas would be delivered to some generators during the few hours per day they needed to be in service, generators were required to schedule gas deliveries and operate for a full day at extremely high prices – even if less expensive power was available. Natural gas scheduling issues caused most of the $597 million in out-of-market make-whole (uplift) charges for January 2014.

How Reliability Was Maintained

Throughout January, PJM employed a number of its pre-defined steps to maintain the stability of the grid and ensure a reliable power supply for consumers. PJM called on all available resources, issued public appeals for conservation and called on load management resources, which responded voluntarily because January was not yet part of the period when load management capacity resources were required to respond. However, even on the day with the tightest power supplies – January 7 – several steps remained before electricity interruptions might have been necessary.

During these periods of unprecedented winter demand, PJM undertook extensive advance communications to its stakeholders, state and federal officials and the public in order to ensure they had full information and awareness of system conditions. The value of increased communication and coordination of information was clearly demonstrated with states and stakeholders as both the public and the summer-only demand response customers were asked to voluntarily reduce demand.

Action Items

While PJM and its members met the challenges from the extreme January 2014 weather, the lessons learned will be used to improve operations and market processes. The PJM community will consider ways to:

- Improve generator availability and performance during extreme weather events,
- Implement performance verification or testing of generation in advance of winter operations,
- Continue to engage in discussions with industry and regulators to improve natural gas and electricity market alignment,
- Implement market mechanisms that encourage better generator availability, such as incentives for ensuring fuel availability or dual-fuel capability, and
- Review the cost allocation for uplift charges and investigate a mechanism to allocate uplift costs during emergency operations that minimizes volatility.

Organization of this Report

The following report provides the operational planning and actions and the market impacts of the extremely cold weather in the PJM footprint in January 2014. The report consolidates data and responses provided to stakeholders, Congress and the Federal Energy Regulatory Commission and provides additional analysis that PJM has conducted to better understand and learn from the cold weather operations.

The report is structured into discussions of the Polar Vortex of January 6-8, the Winter Storms of January 17-29, the operational conditions and ultimate market implications of the extreme weather. The final section shares recommendations.

Typical Preparation for an Operating Day

Beginning a week prior to an operating day, PJM creates and publishes a forecast of expected demand for electricity (load forecast) and monitors factors driving the load forecast, such as weather forecasts and historical patterns of usage. The forecast is updated multiple times every day leading up to the operating day as the driving factors are updated. Because some generators require long notification and start-up times (up to six days), PJM examines expected system conditions to determine if it is necessary to notify these generators that they are expected to be needed.

Approximately three days prior to an operating day, PJM's planning becomes more detailed. PJM staff begins studying transmission and generator outages, load forecasts, weather and other expected factors to prepare for expected conditions during the operating day. The expected system conditions dictate the amount of preparation required. (For example, due to the combination of the weather and the Martin Luther King Jr. Day holiday, preparations began early prior to the severe winter storm expected around January 21, 2014.) PJM will analyze, communicate, study and revise its analysis and operating strategy multiple times as needed as more information about an operating day becomes available. For instance, PJM may request that transmission outages in progress be restored as quickly as possible to prepare for extreme weather conditions and then will update the analysis to reflect these conditions.

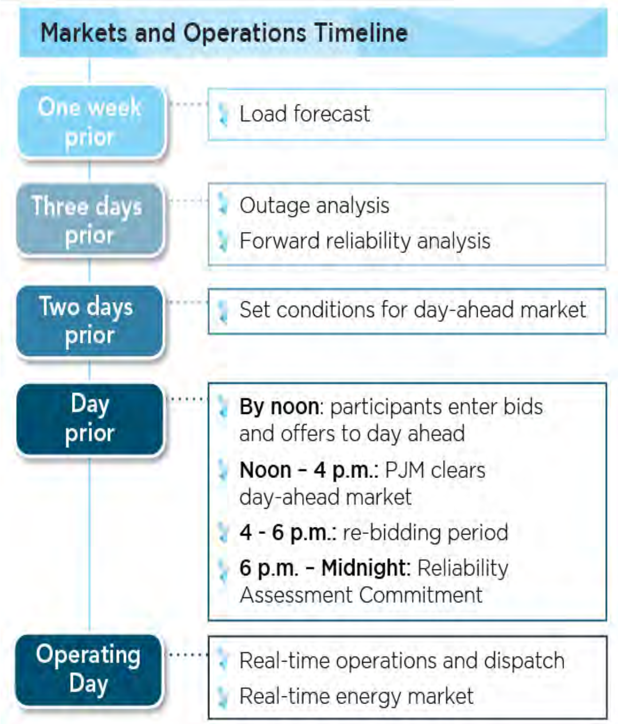
Two days prior to an operating day, PJM will begin to set up the conditions such as the expected outages and conditions for the operating day in the model for the Day-Ahead Energy Market. (The Day-Ahead Energy Market offers an opportunity for market participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risk of exposure to real-time prices.)

Market participants have until noon of the day prior to the operating day to submit their bids and offers for the Day-Ahead Market. Several types of entities participate in the Day-Ahead Energy Market. Generation owners submit their offers to supply power and will adjust offers for factors such as the cost of fuel. Load serving entities will submit bids for their expected need for electricity for the operating day. For a typical operating day, a load serving entity often will procure 90 to 95 percent of its expected demand in the Day-Ahead Market with the remainder being held back to account for forecast uncertainty. Market participants also may submit various "virtual transactions," which are offers to buy or sell at particular locations that are not associated with physical generation or customers. Market participants typically use virtual transactions to hedge risk, mirror physical commitments or account for their expectations of market conditions.

When the Day-Ahead Market closes at noon on the day prior to an operating day, PJM begins the process of clearing the market, and the results are made available by 4 p.m. the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what actually occurs in the operating day is addressed in the Real-Time Energy Market.

Between 4 p.m. and 6 p.m. the day prior to the operating day, generators which were not committed in the Day-Ahead Market can revise their offers to sell power. The window allows a generator to adjust its offer prior to the operating day to better reflect the cost of fuel. The uncertainty of both natural gas costs and availability makes these types of adjustments necessary and useful.

Figure 1: Market and Operations Timeline



As mentioned above, the load levels bid into the Day-Ahead Market typically do not meet the levels expected during the operating day. So, after 6 p.m. PJM begins the Reliability Assessment Commitment (informally called the "Reliability Run"), which ensures that adequate generation is committed to meet the demand plus reserves, while minimizing start-up and no-load cost. (Reserves are used to keep the lights on when unexpected events occur, such as a large generator going off line.) Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. PJM also performs additional reliability analysis to ensure all transmission facilities will be operated within their equipment limits when committing generation. During the severe winter weather events, PJM also communicated extensively with both generation owners and gas pipeline operators in order to adequately understand the likelihood that natural-gas-fueled generators would be able to procure the gas they needed to operate.

On a typical winter day, PJM's peak load for the day averages approximately 106,000 MW. Beyond the expected demand, PJM also will commit approximately 4,000 MW of reserves. In order to provide a sense of scale, the combination would be enough power to serve about 91,200,000 homes. (One megawatt is enough power to serve 800 homes. A typical large nuclear power plant provides 1,000 MW of energy.)

Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintain adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy

Market using the offers from generation resources and demand resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in generation or demand from the Day-Ahead Energy Market commitments are cleared at price levels determined by the Real-Time Energy Market.

The Polar Vortex, January 6-8

Conditions

The January 6-8, 2014, Polar Vortex brought prolonged, deep cold temperatures throughout the entire PJM Interconnection footprint. System operators had to contend both with record high electricity use and much higher than normal generator outages. Nevertheless, power supplies were maintained without interruption.

Demand for electricity because of heating needs set a new wintertime peak demand record of 141,846 MW the evening of January 7. However, during the peak demand hour, 22 percent of generation capacity – including coal, gas and nuclear – was out of service. The generation forced outage rate was two to three times higher than the normal peak winter outage rate of around 7 to 10 percent. During the coldest two days of the period, PJM called upon all available resources: all available generation was scheduled, demand response was called on throughout PJM, shortage pricing went into effect when reserves were low, and emergency power was purchased above normal offer caps. Demand response and shortage pricing raised locational marginal prices[3], which reflected real-time grid conditions and costs.

This section will detail the advance actions PJM took to prepare for the extremely cold weather. The events that occurred during the operating days of January 6-8 will be discussed along with the actions taken by PJM to maintain reliability. Finally, this section will review the market outcomes as a direct result of the conditions and PJM operator actions.

Advance Preparations

Weather and Load Forecast

In the days leading up to the January 2014 Polar Vortex, PJM expected extremely cold weather. Starting Tuesday, December 31, 2013, meteorologists were tracking a weather front likely to hit the PJM region on January 6-7. On January 2, PJM began tracking a snow storm for January 4-6, to be followed by extreme cold. PJM's staff meteorologist and load forecasting experts reviewed the load forecasting computer models, which forecasted peak demand of 134,000 MW for the evening of Tuesday, January 7, and revised the internal forecast, used for operational planning, up to 140,000 MW based on PJM load forecasting experts' worst-case analysis.

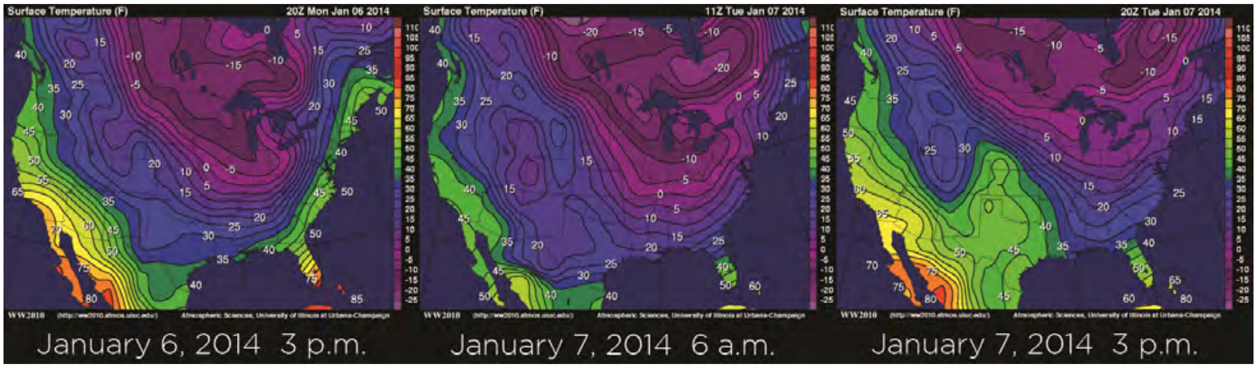
One lesson PJM implemented from the September 2013 Heat Wave[4] was to alert PJM's load forecasting experts when the temperature forecast, an input into the load forecasting engine, changes more than 8-10 degrees from the previous day. In such scenarios PJM can experience corresponding load forecast errors. On December 31, PJM load

3 Locational marginal price (LMP) is the wholesale price for electricity on different parts of the system. This price includes a system energy price, transmission congestion cost, cost of marginal losses and the effect of reserve shortages.

4 http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx

forecasting experts were alerted to large temperature changes expected on January 6. Using historical load curves, load and weather forecast models, and experience, the load forecast was adjusted to 140,000 MW for reliability study and generation commitment purposes. This revised load forecast was communicated to PJM's transmission and generation owners.

Figure 2: Cold Temperatures Envelope the Region



Source: University of Illinois at Urbana-Champaign

In response to actual temperatures projected to fall near or below 10 degrees Fahrenheit, PJM issued Cold Weather Alerts. (A Cold Weather Alert is the first step PJM takes to prepare PJM staff and PJM member company personnel and facilities for expected extremely cold weather conditions.) PJM issued the first Cold Weather Alert on Friday, January 3 for January 6 and 7.

Operational Planning and Advanced Communications

PJM held conference calls with transmission and generation owners as well as neighboring entities to ensure full awareness of the pending weather and the projections for load. PJM instructed members to begin taking steps to ensure availability of all transmission and generation resources, which includes cancelling planned outages, recalling existing outages where possible and communicating to PJM any concerns about equipment, fuel, unit restrictions, etc. It was very important for PJM to get the messages out prior to the weekend when staffing would have been at reduced levels, making it more difficult to prepare. PJM requested units which could not acquire primary fuel to switch to alternate fuel.

Each day leading up to the Polar Vortex, PJM updated its operating plan based on new information on system conditions. PJM issued alerts, increased the frequency of communications with appropriate parties (transmission owners, generators, natural gas pipelines and other relevant stakeholders) and finalized staffing plans.

Waiver to Communicate Freely with Natural Gas Pipelines

In expectation of the high natural gas demand due to extremely cold weather and the potential for subsequent increases in both electric generation and heating later in the winter, PJM sought to better coordinate operations with the natural gas pipelines by sharing market sensitive information.[5] On January 3, 2014, PJM submitted two requests

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5 The Federal Energy Regulatory Commission recently had issued Order 787 allowing such information exchange, but there had not been sufficient time to implement the changes to PJM's governing documents before the severe weather events.

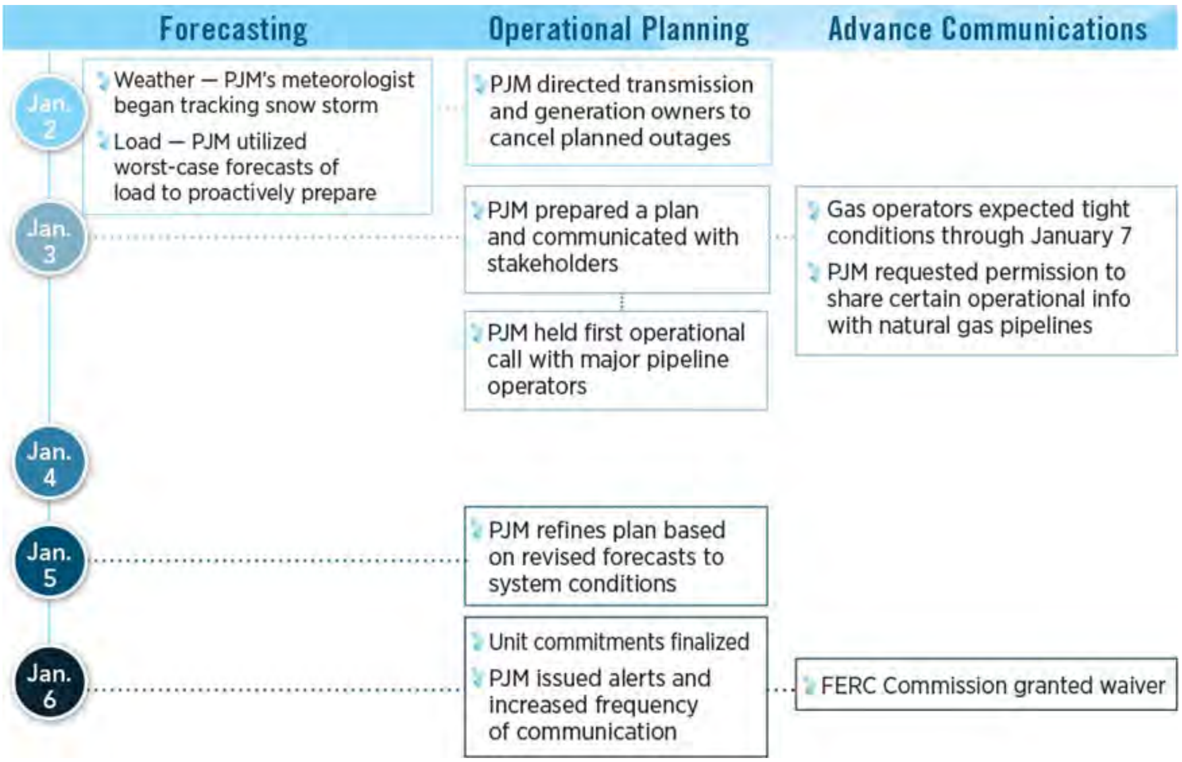
to the Federal Energy Regulatory Commission for waivers of certain provisions of PJM's governing documents that would permit PJM to share certain non-public information with natural gas pipeline operators during the forecasted extreme weather conditions. The waivers, the first covering one week in duration and the other until March 31, 2014, were to allow such communications until appropriate language could be incorporated into the PJM governing documents. FERC responded promptly to PJM's filing, which enabled those communications to commence quickly.

On January 3, PJM held its first operational call with the major pipeline operators to discuss natural gas conditions through the week starting January. 5. Overall, natural gas pipeline operators expected the capacity on the pipelines and the natural gas market to be very tight and expressed doubt any interruptible transportation would be available through most of the coming week and particularly on January 7. However, pipeline operators indicated that firm transportation customers would still be served. Throughout the course of the Polar Vortex and the Winter Storm later in the month, PJM held conference calls with all available interstate pipelines and had individual discussions with some of the pipelines.

Several pipeline operators also issued notices that limited non-firm natural gas deliverability. More information about pipeline notices can be found in

Appendix C: Natural Gas System Critical Notices. The effect of these pipeline issues in the electricity market becomes apparent when examining the generation which was unable to operate on January 7 as discussed further in the Generator Performance: Outages subsection on page 24 of this report.

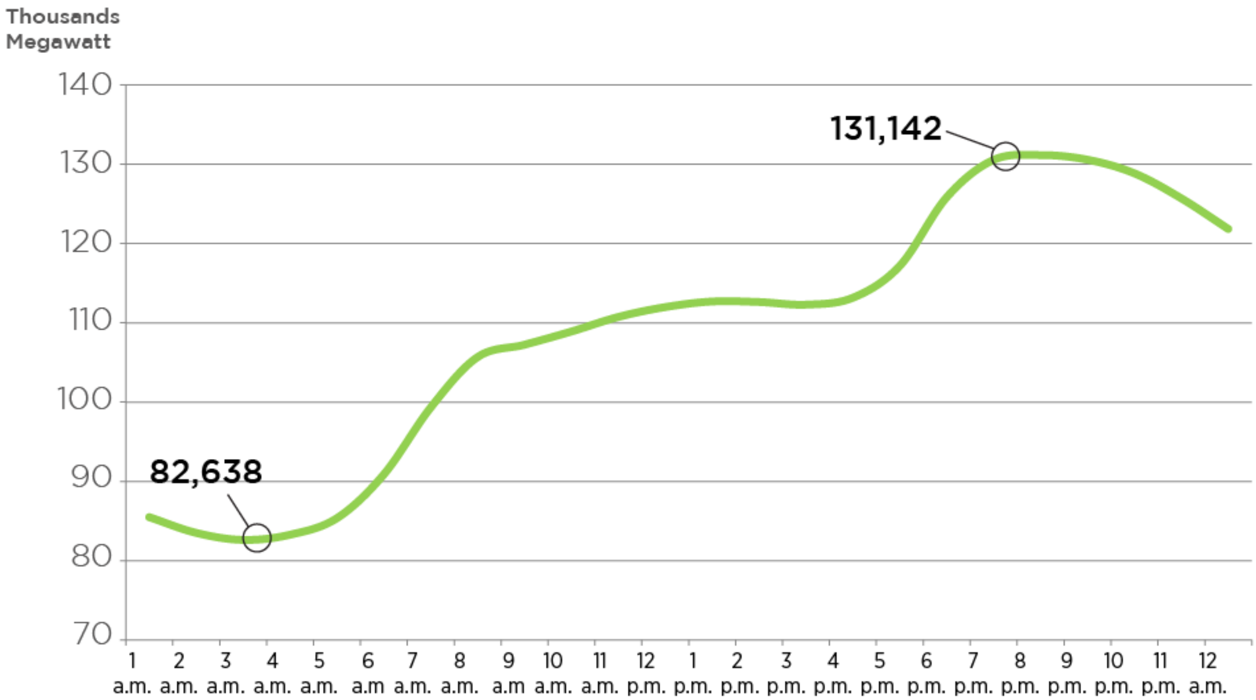
Figure 3: PJM Preparation for the Polar Vortex



Emergency Procedures

PJM reliably met the demand on January 6 employing several Emergency Procedures and market mechanisms. Although the 131,142 MW peak load on the evening of January 6 was not one of PJM's top ten peak winter load days, it was roughly 25,000 MW above a typical winter peak day. The load curve on January 6 also was very unusual and challenging as the extreme cold front moved into the PJM territory during the day. Typically, PJM winter load curves produce two distinct peaks. This twin peak consists of one peak in the morning and one in the evening, both usually similar in magnitude and each approximately four hours long with a slight valley in between. As the extreme cold front moved into the PJM region throughout the day, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. This steep slope from valley to peak challenged the operators to keep up with the load that was coming in fast and high. PJM needed to bring on many units that had not run in months: close to 50,000 MW (approximately 175 – 200 units) in a short period and during extreme cold. The speed and magnitude of the load change coupled with units' start failures (approximately 45 percent for combustion turbines) and other issues caused by extreme weather made the day extremely challenging.

Figure 4: PJM Load, January 6, 2014


Thousands Megawatt
140
130
120
110
100
90
80
70
131,142
82,638
1 a.m.
2 a.m.
3 a.m.
4 a.m.
5 a.m.
6 a.m
7 a.m.
8 a.m.
9 a.m
10 a.m.
11 a.m.
12 p.m.
1 p.m.
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5 p.m.
6 p.m.
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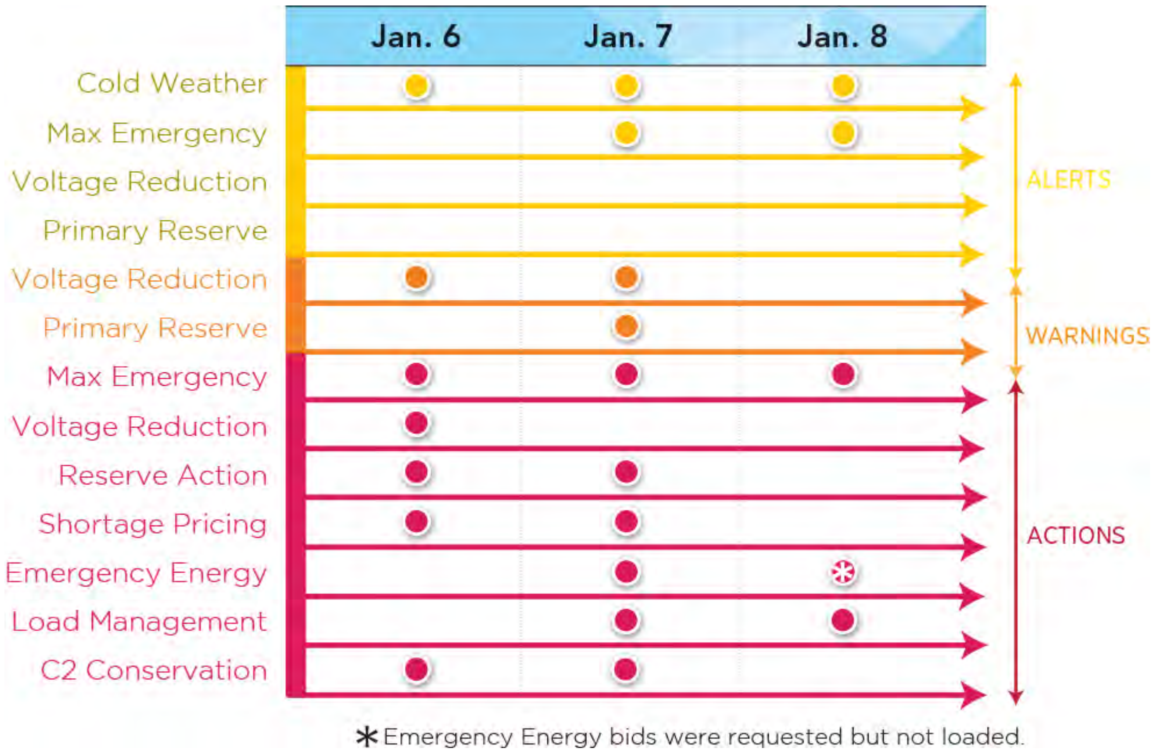
11 p.m.
12 a.m.

Figure 5: Emergency Procedures during the Polar Vortex



A detailed listing of emergency procedures taken can be found in Appendix E: Emergency Procedures in January.

In addition to the Cold Weather Alerts issued prior to January 6, PJM issued a Max Emergency Generation Alert[6] for Tuesday, January 7 for the entire RTO. PJM also issued at the same time a North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) Level 1 to inform PJM's neighboring systems that PJM expected to run all available generating resources to meet the demand for electricity. The Max Emergency Generation Alert occurs when PJM forecasts that current reserves may not be high enough to meet the PJM operating reserve requirement. At the time, PJM's Energy Management System was calculating the operating reserve requirement to be 9,939 MW and estimated the reserve amount to be 8,075 MW. PJM issued this alert to notify all capacity and energy resources that they likely would be needed on Tuesday during the peak hours.

At just about 5 p.m. on Monday, January 6, PJM initiated a synchronized reserve event to maintain system reliability in response to the nearly concurrent, but unrelated, loss of two large generating units totaling 1,562 MW.[7] The Northeast Power Coordinating Council provided 775 MW of shared reserves to PJM from 5:01 p.m. to 5:15 p.m. to assist with the unit losses.

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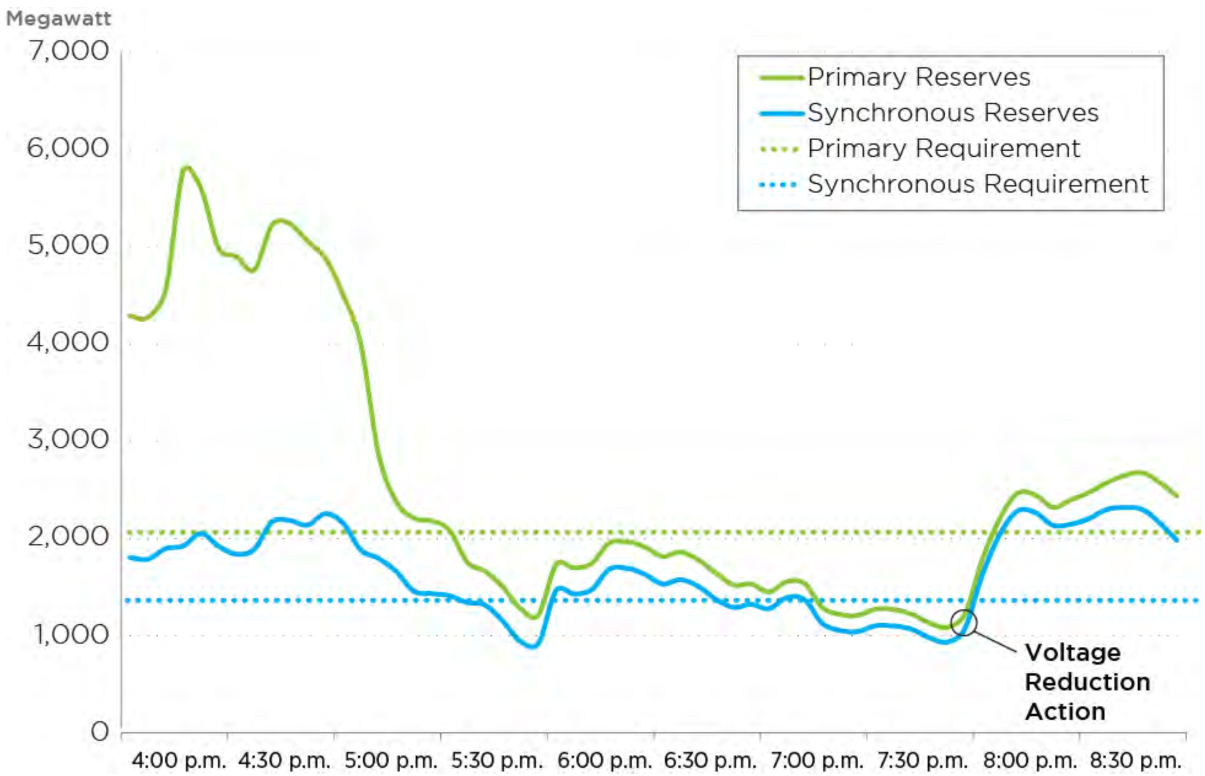
6 The Maximum Emergency Generation Alert provides a day-ahead alert that system conditions may require generation to be loaded above the maximum economic level and that use of the PJM emergency procedures may be implemented. This requirement varies each day and is used by PJM to ensure adequate backup generation is available for the grid in the event of an emergency. Operating reserve is generation available from either offline or online units within 30 minutes of PJM's request. Reserves are scheduled to meet operating reserve requirements in the Day-Ahead Market. PJM Manual 13, Emergency Operations, Section 2.

7 Synchronized reserve is either generation that can begin producing electricity within 10 minutes or customer use of electricity that can be removed from the system within 10 minutes. This procedure is used to direct all available generation resources to quickly increase (or decrease for demand response resources) their output to respond to the request.

In addition to the two large units that were lost, between 5:00 p.m. and 7:30 p.m. on Monday, January 6, PJM lost an additional 6,400 MW of capacity due to unit trips, unplanned generator reductions and fuel restrictions. At that time, PJM issued a Voltage Reduction Warning[8] followed immediately by a Maximum Emergency Generation Action, both for the entire RTO. This real-time Voltage Reduction Warning notified members that the available synchronized reserve was less than the requirement and that a voltage reduction might be required. Synchronous reserves were approximately 900 MW compared to a 1,372 MW PJM requirement at the time. Approximately 20 minutes after issuing the warning, PJM issued a Voltage Reduction Action. Shortage pricing[9] was triggered by this Voltage Reduction Action. The combination of the load reduced by the Voltage Reduction Action and the power imports attracted by the Shortage Pricing event helped restore primary reserves to above 2,400 MW.

Figure 6: Voltage Reduction Restores Reserves



In addition to the emergency procedures that PJM implemented, PJM also communicated throughout the day with its neighboring operators and reliability coordinators to ensure the overall reliability of the Eastern Interconnection. PJM's neighboring entities were affected by the same extremely cold temperatures and generator forced outage rates experienced by PJM. The evening of January 6, power imports to PJM averaged 1,000-1,500 MW compared to more typical power imports of 4,000-5,000 MW.

8 A Voltage Reduction Warning (and Reduction of Non-critical Plant Load) informs members that Synchronized Reserve is less than required and present operation has deteriorated such that a voltage reduction may be required. It is trigger when actual Synchronized Reserve is less than the Synchronized Requirement. All secondary and primary reserve (except megawatts in Max Emergency) are first moved to Synchronized Reserve status.

9 Shortage Pricing is a methodology for accurately pricing energy and reserves so the resulting prices reflect the state of the system both approaching and during times of reserve shortages.

PJM participates in two shared reserves groups[10], Northeast Power Coordinating Council (NPCC) and the Virginia-Carolinas Reliability Agreement (VACAR). PJM supplies shared reserves when requested by those groups, and PJM also requests shared reserves to help recover from the loss of internal PJM generation. Below are the times on January 6 when PJM relied on electricity reserve imports from other systems to meet its own energy needs, outside of normal operations:

- Monday, January 6, 2014: 5:01 p.m.-5:15 p.m., PJM received 775 MW from NPCC.
- Monday, January 6, 2014: 11:20 p.m.-11:34 p.m., PJM received 800 MW from NPCC.

Shared Reserves were cancelled once PJM restored the generation/load balance with internal resources and market-priced imports.

On Monday, January 6, 2014, 9:15 p.m.-9:56 p.m., PJM provided 163 MW of shared reserves to NPCC.

Operations – January 7

Based on the actual conditions experienced on Monday evening, load coming in as high and as fast as it did and high forced outage rates (approximately 17 percent[11] during the Monday evening peak), PJM took additional steps to prepare for operations on Tuesday, January 7. The Cold Weather and Max Emergency Alerts for Tuesday remained in place. In addition PJM issued a Level 2 Statement for Cold Weather for the entire RTO. This statement is a request to the public to conserve electricity because of developing power supply problems. PJM issued the Level 2 Statement to the PJM transmission owners the evening of January 6, indicating the request would be for Tuesday, January 7, during the morning and evening peaks.

Tuesday, January 7, was the coldest day of the week across the PJM footprint. Daily low temperature records were set or tied in Philadelphia, Richmond, Pittsburgh, Cleveland and Columbus. High temperatures were in the single digits and low teens for many areas of PJM, and lows were 10-30° F below normal. On January 7, PJM experienced the highest winter peak demand in its history.

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10 Reserve sharing groups allow entities to share reserves on a routine basis and deploy those reserves to recover from a system event such as loss of generation.

11 http://www.pjm.com/~/media/documents/reports/20140113-pjm-response-to-data-request-for-january%202014-weather-events.ashx

Figure 7: Minimum Temperature for Each Day in January 2014: Columbus, Chicago, Philadelphia and Richmond

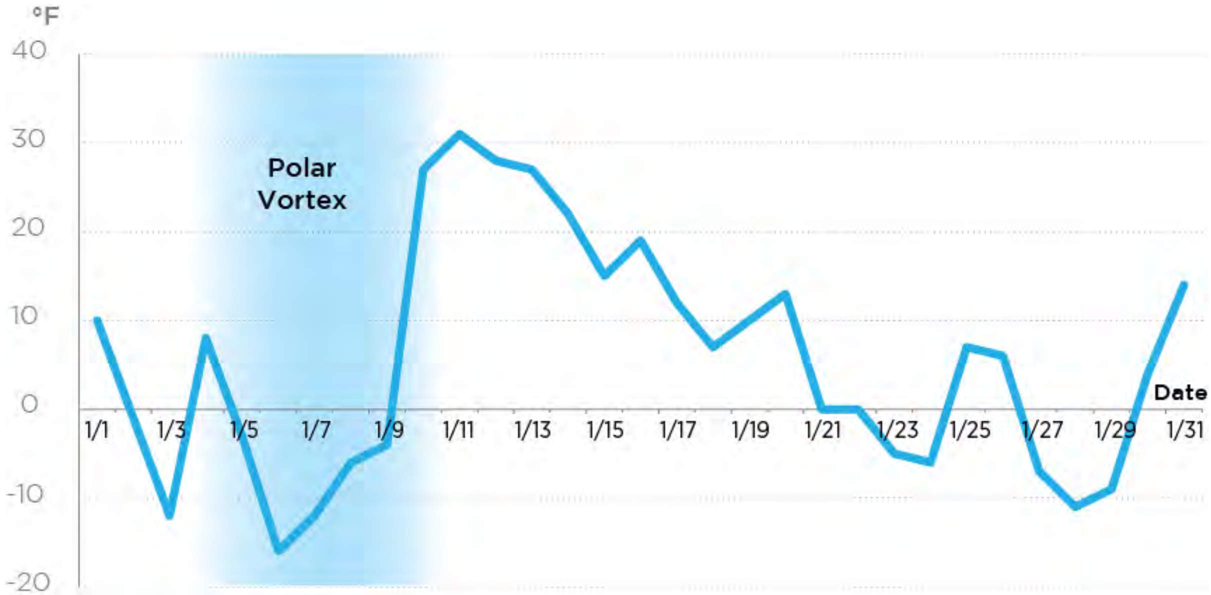
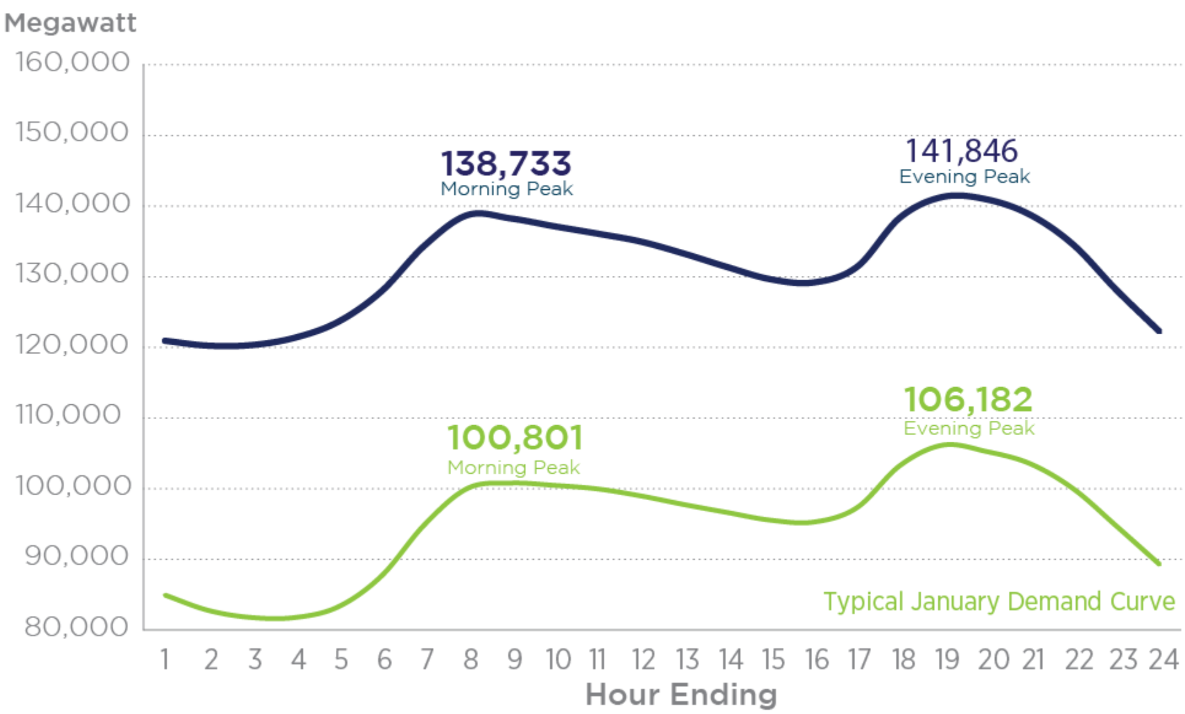


Figure 8: January 7 – Peak Load vs. Typical Load (Winter load peaks twice each day.)

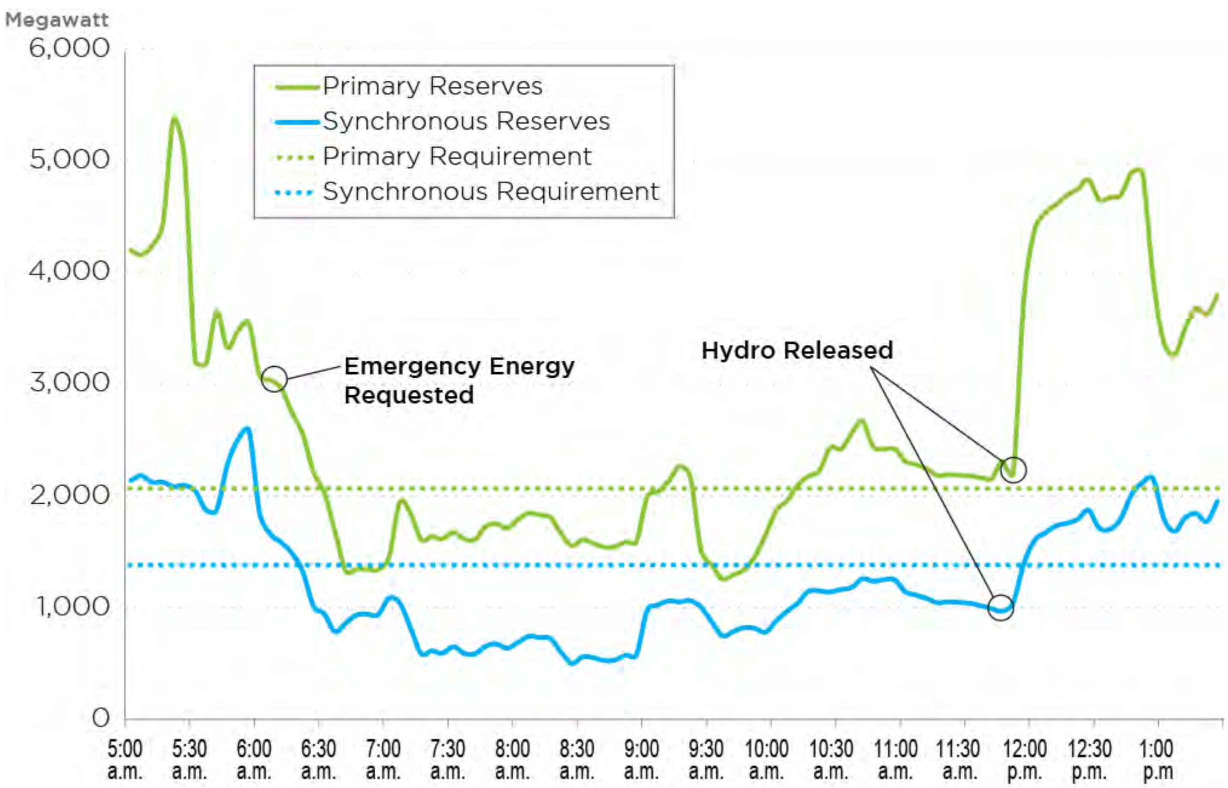


The PJM demand curve for January 7, 2014, was 35,000 MW higher than typical of a January peak load.

Emergency Procedures – January 7

Early on Tuesday morning, PJM initiated a number of steps to prepare for the operating day. First, at 12:55 a.m., PJM issued a Primary Reserve Warning[12] for all day Tuesday. This warning was issued to warn members that the available primary reserves were forecasted to be less than the required amount for the peak later that day and that operations were becoming critical. PJM estimated 1,950 MW of primary reserves were available compared to its 1,980 MW reserve requirement. The Primary Reserve Warning triggered shortage pricing. (See Energy Prices and Shortage Conditions Market Outcome on page 27 for more discussion on shortage pricing.) PJM also issued a Voltage Reduction Warning at 2:51 a.m. for the morning peak to allow time for transmission owners to staff substations as appropriate.

Figure 9: Reserves – January 7, 2014



While reserves were tight, a Voltage Reduction Action, one of the next emergency procedures to be implemented, was not needed to meet the evening peak because of a combination of the other emergency procedures issued, such as Max Generation Action (at 3:00 p.m.), Load Management and pricing changes triggered by shortage pricing, which attracted additional power imports.

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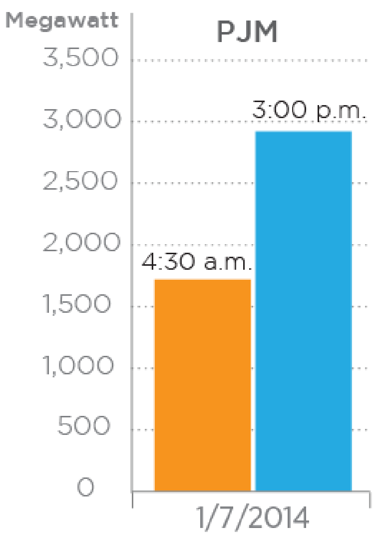
12 The purpose of a Primary Reserve Warning is to warn the members that the primary reserve is less than required and operations are getting critical. It is issued when the primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement. Transmission and generation dispatchers move secondary reserve to primary status (so that it can be producing electricity within 10 minutes from a request) and schedule all available generation. Secondary reserve is reserve capability that can be fully supplying electricity within 10 to 30 minutes following the request of PJM. In addition, Transmission and generation dispatchers ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted. By deferring maintenance or testing, the equipment can remain online to provide energy, and the system will not have to draw from emergency backup sources.

More at: http://www.pjm.com/~/media/training/core-curriculum/ip-ops-101/ops-101-capacity-shortages.ashx. Slide #22

Demand Response

On January 7, 2014, PJM deployed Emergency Load Management, or demand response, twice. PJM's dispatch personnel first notified DR resources at 4:30 a.m. with a reduction time of 5:30 a.m. for short lead-time registrations[13] and 6:30 a.m. for long lead-time registrations[14]. The load management event ended at 11:00 a.m. For the second event, dispatch personnel notified DR resources at 3:00 p.m. with a start time of 4:00 p.m. and 5:00 p.m. for short and long lead-time registrations, respectively. The second event of January 7 ended at 6:16 p.m. Emergency Load Management reductions were mandatory for only the summer months and voluntary during the winter period.

Figure 10: Estimated Demand Response during the Polar Vortex



The responding, voluntary demand response resources, while only about 20 percent of the demand response capacity, performed very well. Deploying the Emergency Load Management in addition to the Max Generation Action at 3:00 p.m. January 7 not only made additional resources available for the evening peak but also attracted significant additional power imports into the PJM system. The load management deployment in particular attracted imports because it set high prices in PJM ($1,800/ MWh). This combination of emergency procedures and PJM market responses helped PJM successfully meet an all-time record winter peak of 141,846 MW at 7:00 p.m. January 7 with no reliability issues.

Emergency Energy Purchases – January 7

PJM also has the ability to purchase emergency energy from neighbors. Given the amount of forced outages and the Primary Reserve Warning in effect for the day, PJM requested Emergency Energy bids for January 7 between 6:00 a.m. and 11:00 a.m. PJM obtained emergency energy from the following neighboring regions:

- 600 MW: 6:00 a.m. - 11:00 a.m., five hours duration, from the New York Independent System Operator.
- 500 MW: 6:00 a.m. - 9:00 a.m., three hours duration, from Midcontinent Independent System Operator

13 Short lead-time applies to any site registered in the PJM demand response program as a demand resource type that needs up to one hour lead time to make its reductions.

14 Long lead-time applies to any site registered in the PJM demand response program as a demand resource type that needs one to two hours lead time to make its reductions.

On January 7, PJM also provided shared reserves to neighbors during the following times:

- 200 MW: 6:27 a.m. - 7:30 a.m. to VACAR
- 200 MW: 8:45 a.m. - 9:28 p.m. to VACAR
- 200 MW: 8:49 a.m. - 10:35 a.m. to Duke Energy Progress

PJM had to recall the 200 MW of shared reserve obligations to VACAR on January 7 due to PJM's own internal reserve shortages caused by additional units tripping off-line (approximately 900 MW). At this point, PJM was at its lowest reserve level with approximately 500 MW synchronous reserves and 1,167 MW primary reserves available. Once reserves were restored, PJM offered and reactivated the 200 MW shared reserve flow to VACAR. While it may appear counter-intuitive to be import emergency energy from some neighbors while sharing reserves with other neighbors, system conditions across much of the Eastern Interconnection required such teamwork and the ability to adjust plans in real time as the situation demanded.

Operations – January 8

PJM continued to prepare for cold weather operations on Wednesday, January 8. Forecasted load was 134,107 MW at 9:00 a.m. with forecasted temperatures slightly higher across the RTO than the previous day. The expected conditions prompted PJM to issue a Cold Weather Alert and a Maximum Emergency Generation Alert. As the morning load pickup began, PJM developed a plan to implement specific emergency procedures in order to meet expected system load. At 5:00 a.m., PJM called for voluntary demand response resources and posted a NERC EEA Level 2 to notify other reliability coordinators of its actions.

A Maximum Emergency Generation Action was declared in conjunction with the implementation of voluntary demand response, but generation owners were advised not to load maximum emergency capability until PJM specifically contacted them. PJM also issued a request for emergency energy bids at 5:30 a.m. in order to identify options for meeting system load and to see if the bids were more economic than voluntary demand response resources. As system load was trending below forecasted load in the morning hours, PJM reevaluated the operational plan and cancelled the voluntary demand response. PJM did not need to issue any additional emergency procedures on January 8. Actual load at the morning peak was 133,288 MW at 8:00 a.m. with actual temperatures 4-7 degrees higher across the RTO than on the previous day.

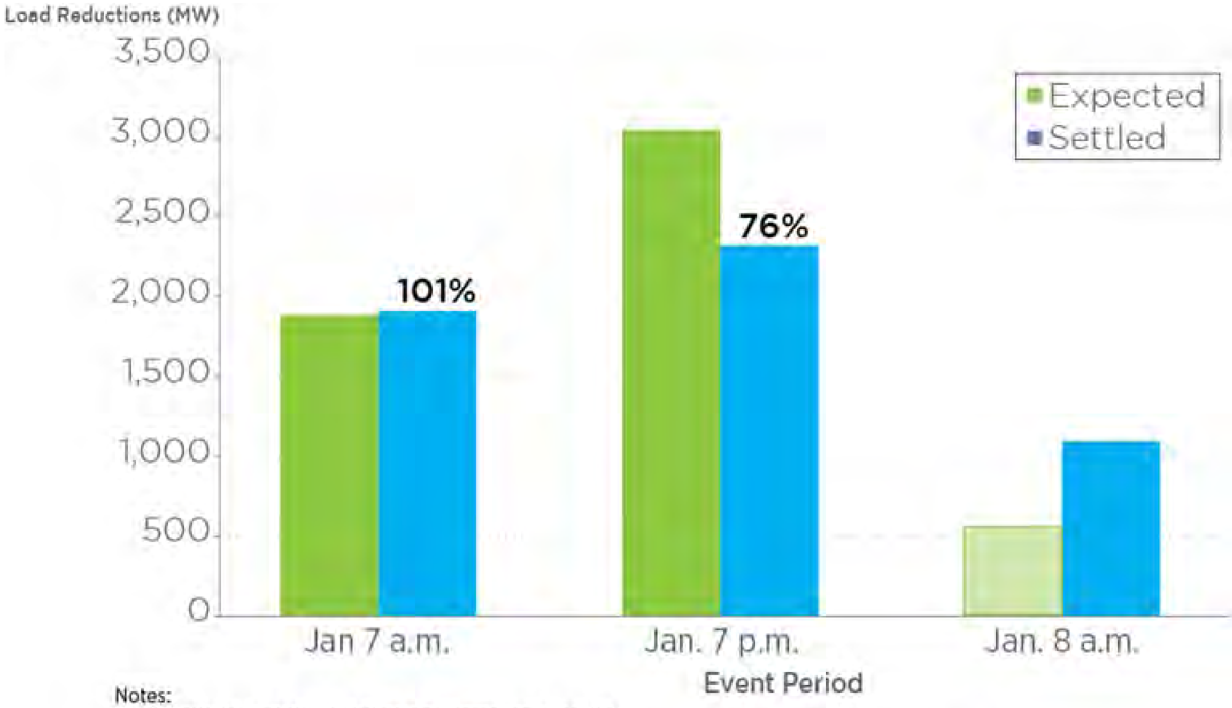
Operational Observations and Challenges

Demand Response and Renewables

Although operational conditions were tight during the Polar Vortex, some variables exceeded PJM's expectations in real-time: the availability and response of voluntary demand response, the response of the stakeholders to the public appeal for conservation, and the performance of wind-powered generation.

Demand response, although not required to respond during the winter this year, did respond and assisted in maintaining the reliability of the system. In fact, the total amount of demand response provided was larger than most generating stations. During the Polar Vortex, PJM called on demand response three times – the morning and evening of January 7 and the morning of January 8 throughout the RTO. Even though demand resources were not obligated to respond during this period, close to 25 percent of the demand response resources registered in PJM did respond and helped PJM manage the grid on the all-time winter peak day. This experience demonstrates the year-round value of demand response.

Figure 11: Polar Vortex Demand Response Performance

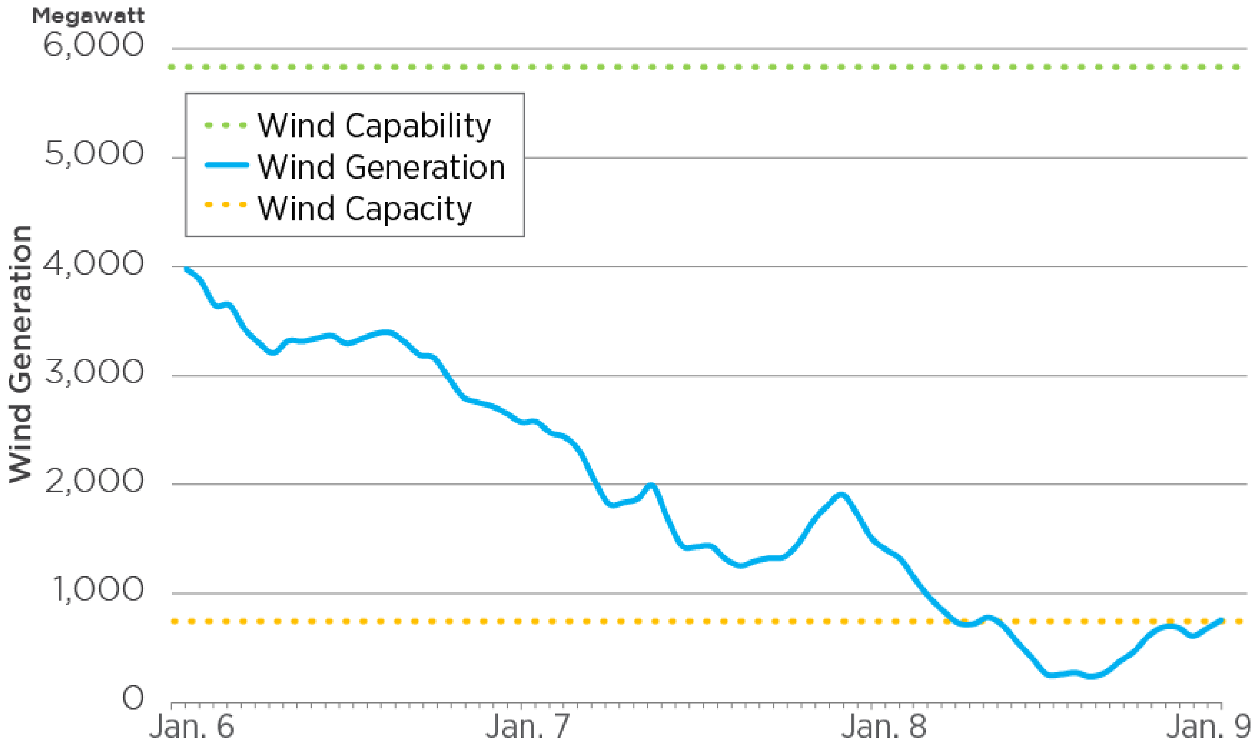


Notes:
1. DR events dispatched during non-compliance period.
2. Expected Energy Load Reductions (MW) - CSP reported estimate based on current market rule.
3. MW value is average hourly load reduction for non-ramp in hours.
4. Event on Jan. 8 was cancelled by PJM prior to official start time. In order to honor the Emergency DR resource 2-hour minimum down time, PJM allowed CSPs to settle if their load reduction had started prior to cancellation and/or needed to reduce for 2 hours. PJM estimated amount of DR that needed to continue to reduce for 2 hours. "Performance" for this event cannot be measured based on the circumstances of this event

PJM issued a public appeal for conservation for the entire RTO, the evening of January 6 for Tuesday, January 7, during the morning and evening peaks. The statement was shared with the communications departments of transmission owners, which in turn communicated to their stakeholders. While PJM does not currently have a measurement of the energy conservation achieved, it believes the request for conservation had a positive impact on the real-time conditions.

PJM also saw up to 4,000 MW produced by wind power during the peak load periods of January 6-7. Figure 12: shows that wind power produced at a level above the calculated wind capacity, (typically 13 percent of total wind capability). The wind power produced had a positive impact on supply and contributed to PJM's ability to maintain reliability.

Figure 12: Polar Vortex Wind Generation



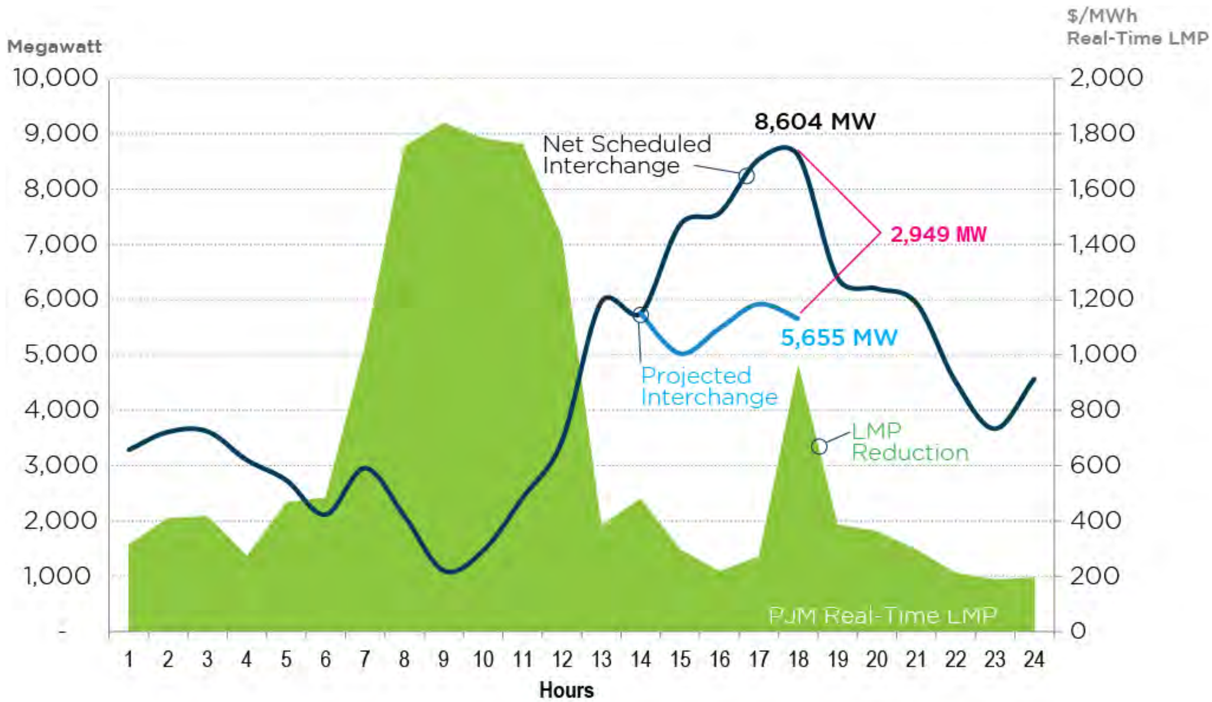
Managing Interchange

Managing interchange, or energy transfers across the RTO, was a challenge during the Polar Vortex, particularly during the afternoon of January 7. PJM expected (based on energy imports scheduled four hours ahead) about 5,600 MW of interchange into PJM during the evening peak. PJM received almost 3,000 MW more than expected. Hourly energy prices in PJM during the evening peak were $750-$800, and prices in MISO were approximately $400-$500 less than in PJM. The NYISO's prices were approximately $50-$100 less than PJM's prices. Market participants responded to the disparity in neighboring prices and began importing power into PJM during the evening peak. In particular, imports from MISO increased significantly when compared to imports during the morning peak.

When PJM receives more energy transferring into the RTO than expected, the market becomes flooded with supply, and prices drop accordingly. This interchange volatility changed the situation for which PJM had planned and impacted energy prices, generation dispatch and costs.

Accurately forecasting interchange is a challenge. PJM operators can see only current energy transfers across the system with no certainty of end time or advance notice of future swings. PJM had generation operating with the expectation of a lower level of imports given the conditions across the grid. Imports increased substantially in response to the expectation of higher locational marginal prices set by demand response. This increase in supply caused LMPs to drop, and the generation PJM had operating for reliability was left operating at costs above the locational marginal price, resulting in uplift payments to these generators. Though not a reliability concern, the situation impacted the economics of the system, which will be discussed further in the Uplift subsection on page 44.

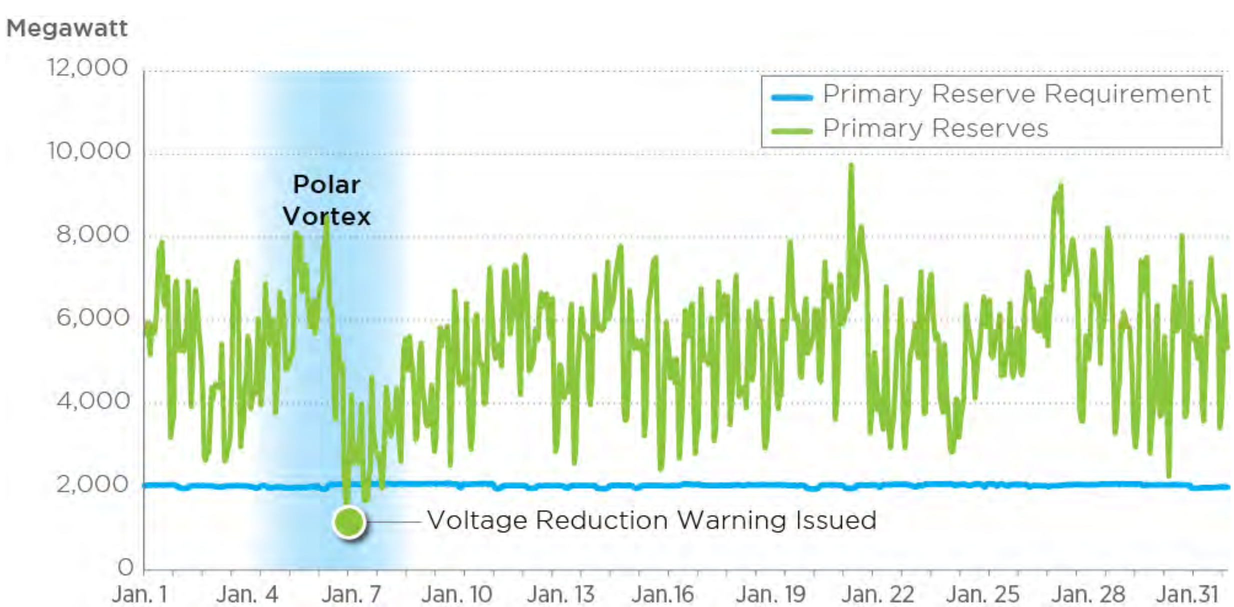
Figure 13: Interchange and Locational Marginal Prices on January 7, 2014



Managing Reserves

PJM had adequate reserves for most of January – with the exception of the evening of January 6 and the morning of January 7 when available reserves dipped below the PJM reserve requirement prompting PJM to issue a series of emergency procedures to ensure adequate reserves on the system. The reserve shortfalls largely were due to a combination of generator outages and extremely cold weather demand. See Figure 14: for January's primary reserves compared to the reserve requirement.

Figure 14: Primary Reserve and Requirement – January 2014



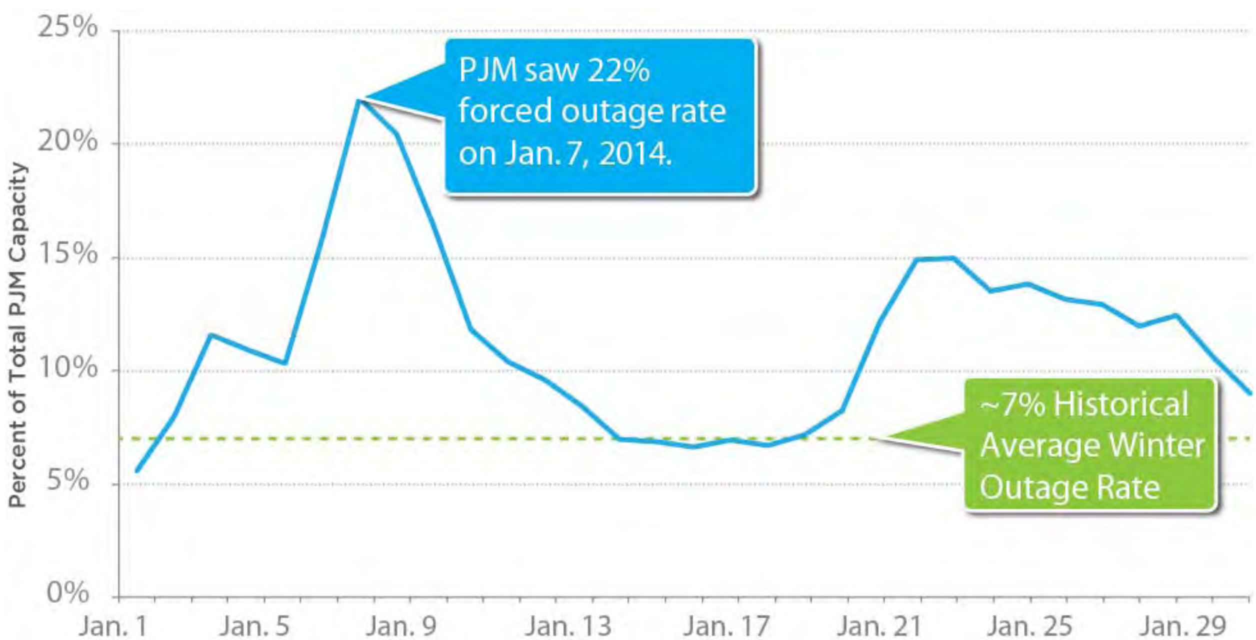
When PJM has a sustained shortfall of its primary reserve capability, a Primary Reserve Warning is issued as notification of the reserve shortage. On the evening of January 6, PJM additionally issued a Voltage Reduction Warning and Action to maintain reliability. If needed, PJM could have initiated additional emergency procedures to regain its reserve capability. Following the Voltage Reduction Action, primary reserves were restored above the requirement. PJM also had available shared reserves from NPCC and VACAR during this period.

Generator Performance: Outages

Unplanned generator shutdowns and the inability of generators to start – due to the cold, the stress of extended run times, natural gas interruptions and fuel-oil delivery problems – challenged grid reliability and adequate power supplies during the month. A generator's inability to run due to any type of unexpected mechanical or fuel issue is considered a forced outage. Forced outages on January 7, 2014, were 94 percent of the all outages that day.

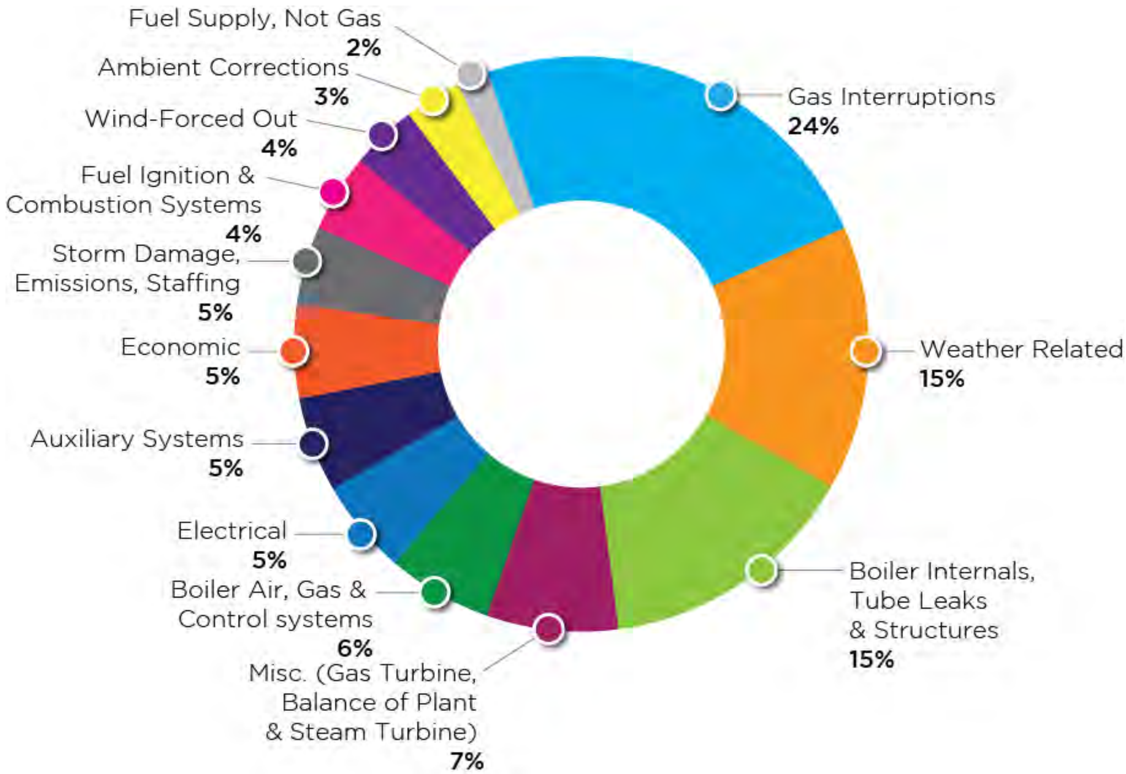
PJM experienced very tight operational conditions and a significantly higher number of forced outages, due to both mechanical problems and natural gas deliverability, throughout January 2014 as compared to a more typical January. At the all-time winter peak at 7 p.m. on January 7, PJM experienced a 22 percent forced outage rate, which was far above the historical average of 7 percent, with a total of 40,200 MW unavailable due to forced outages.

Figure 15: Generator Outage Rate – January 2014



All conventional forms of generation, including natural gas, coal and nuclear plants, were challenged by the extreme conditions. Generators are required to submit outage data after the outage has occurred. Figure 16: shows that the 42 percent of forced outages were due to equipment failures. The other key reason (24 percent of the forced outages) was a lack of fuel to start up and/or run generating units.

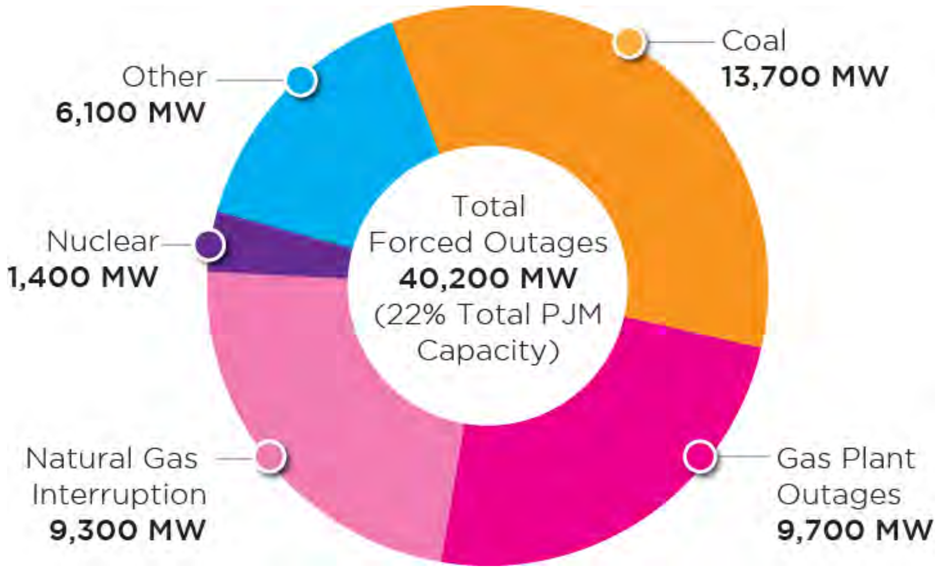
Figure 16: Causes of Forced Outages – January 7, 7:00 p.m.



The breakdown of forced outages by primary fuel type shows that natural-gas-fired generators accounted for 47 percent of the unavailable megawatts and coal-fired generators were 34 percent. For a frame of reference, in PJM, gas-fired plants represent 29 percent of total generation (in megawatts), and coal-fired plants represent 41 percent.[15] These unavailable megawatts were due to either the generator's entire output being unavailable or a limitation on the amount of megawatts the generator could supply to the system.

[15] Installed capacity as of December 31, 2013

Figure 17: Outages by Primary Fuel – January 7, 7:00 p.m.



The 9,300 MW of generation that was unavailable due to natural gas interruptions is a larger amount than PJM reported immediately after January 7. Subsequent to January, PJM worked with generation owners to further validate the outage reasons, and, based on these additional discussions, natural gas issues were found to be larger than initially reported largely due to other generation fuel types being dependent on natural gas and the natural gas infrastructure. An example is a generator that burns oil but that needs natural gas to start up. In a few cases, this startup gas was not available. Please see the Lessons Learned and Recommendations section on page 53 for PJM's preliminary recommendations relative to generation forced outages.

Communication

PJM implemented additional communication procedures based on lessons learned from the September 2013 heat wave and put those practices into effect, such as improved coordination and communication with PJM stakeholders. Internally, PJM activated a new Operation Event Response Team, a cross-divisional group designed to help prepare for, respond to and communicate about operational events, such as capacity emergencies and severe weather. This team was in place nearly every day in January not only to provide PJM dispatch personnel additional analysis and data but also to coordinate information through the appropriate internal and external channels.

PJM communicated with state commissions, state emergency management agencies and state consumer advocates before, during and after key operational events. PJM provided information about system conditions and emergency procedure alerts, warnings and actions via email and group conference calls in addition to ad hoc discussions.

PJM also provided power supply status updates to member communications staff counterparts, held conference calls with member communicators and created and distributed news releases and media advisories. In addition, advisories were provided to the FERC throughout the day during each of the cold weather events in January.

Market Outcomes: Polar Vortex

Energy Prices and Shortage Conditions

As explained above, PJM issued a Voltage Reduction Action on the night of January 6 and a Primary Reserve Warning on January 7. Both actions triggered shortage pricing, a market rule that accurately prices energy and reserves so the resulting prices reflect the state of the system both approaching and during times of reserve shortages.[16]

Shortage Pricing is triggered under either of the following conditions:

- The amount of available reserves is below the reserve requirement for a predetermined amount of time and dispatch systems confirm that the shortage exists. This situation can be due either to the available synchronized reserve megawatts being less than the requirement or available primary reserve megawatts less than required
- A Voltage Reduction Action or a Manual Load Shed Action is implemented.

PJM operators triggered shortage pricing by calling the Voltage Reduction Action across the entire RTO on the evening of January 6, and shortage pricing was triggered by an RTO reserve shortage on the morning of January 7.

Locational marginal prices are determined based on the cost to provide the next increment of energy while respecting the primary and synchronized reserve requirements. PJM's real-time dispatch system and LMP calculation systems include operating reserve demand curves for both primary and synchronized reserves, which are used in the calculation of LMPs to reflect both the price of energy and the price of reserves in an area experiencing a reserve shortage. This coordination is necessary because providing another megawatt of energy will cause an additional megawatt of reserve shortage.

On January 7, 2014, LMPs exceeded $1,800 per megawatt-hour. The price of $1,800 was set by emergency demand response offers, which means that demand response participants responded to calls for emergency energy and high prices to voluntarily curtail their use of electricity in exchange for curtailment payments. Because of the higher offer caps for demand response[17], LMPs may reach $1,800 per megawatt-hour without the existence of a reserve shortage. In January, there were instances where emergency demand response set the price at $1,800 either for the energy component of the locational marginal prices or for congestion.

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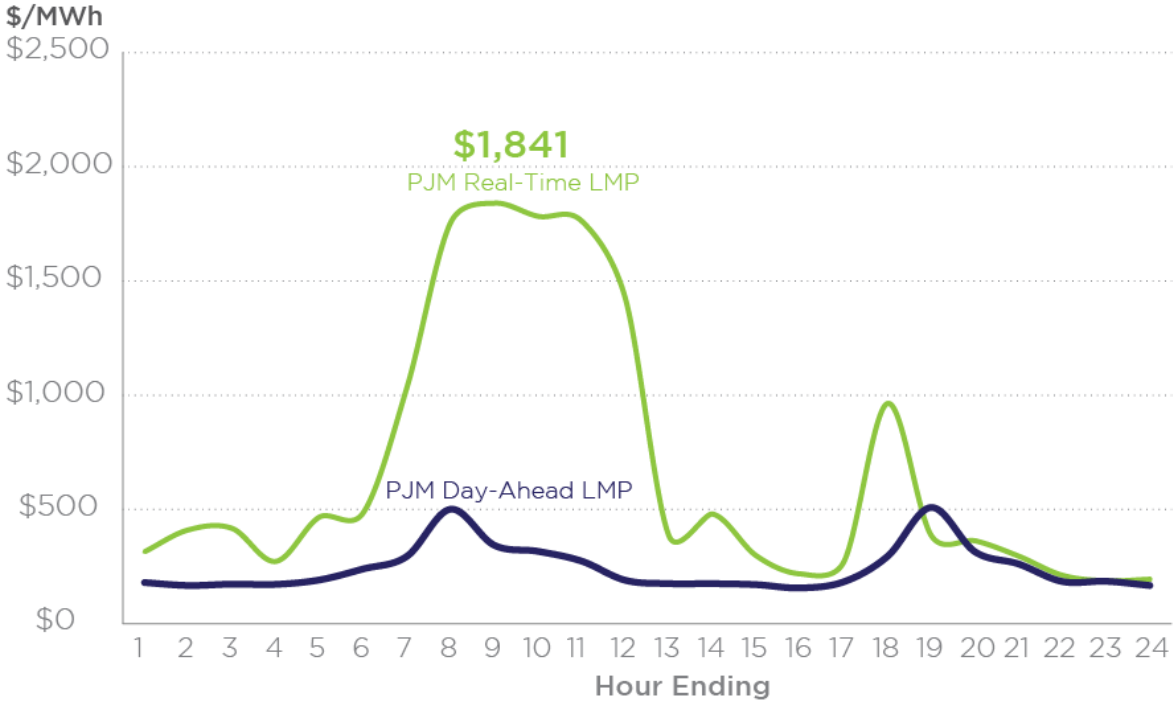
16 For more information on the shortage pricing rules, view training material PJM previously has provided at http://www.pjm.com/markets-and-operations/energy/shortage-pricing.aspx.

17 PJM initially had filed to limit demand resources to the legacy $1,000/megawatt-hour offer cap that has existed for some time for all resources. The FERC conditionally approved PJM's filing subject to several adjustments including the removal of the $1,000/MWh offer cap for capacity demand resources. As a result, demand resources are not limited to the $1,000 offer cap that applies to generation resources. Instead, these resources can offer up to $1,000 plus two times the reserve penalty factor. For the 2013-2014 delivery years, the penalty factor is $400. So, the offer cap applicable to demand resources is $1,800.

Figure 18: Locational Marginal Prices in Shortage

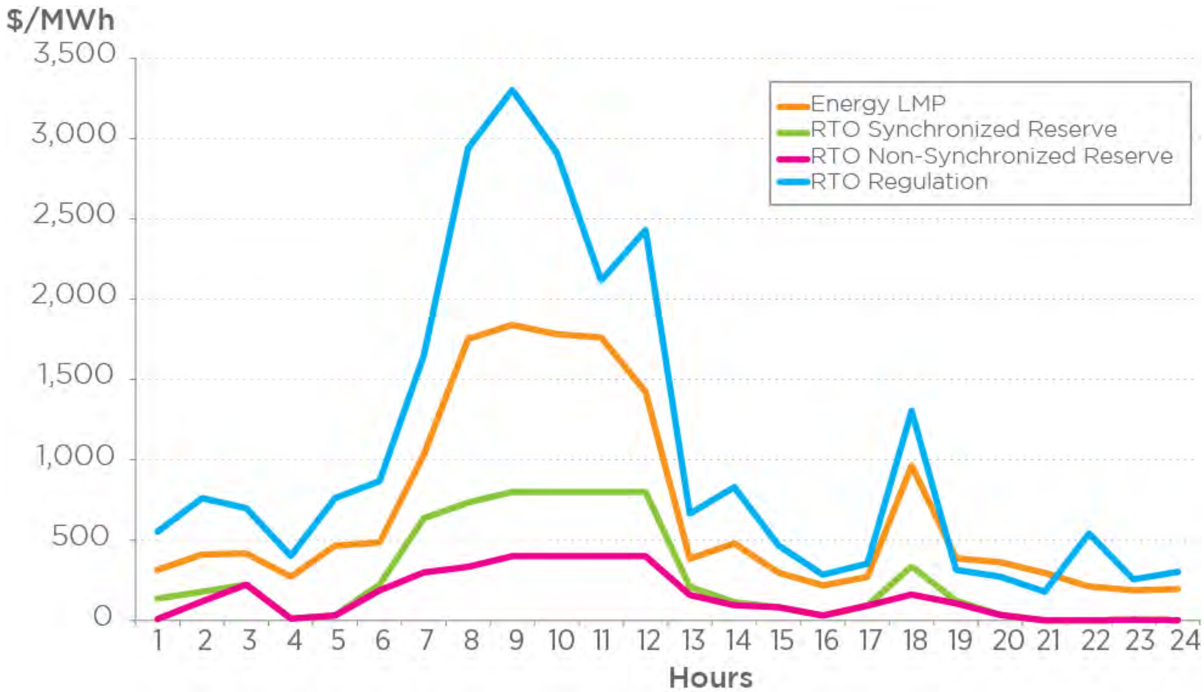


Real Time Locational Marginal Prices are calculated based on five minutes intervals. Although generation usually is the marginal resource setting the price, on January 7, demand response set prices for 63 five-minute energy pricing intervals during the day. Additional information on interval analysis of prices can be found in Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals.

Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserve

During the Polar Vortex, high prices for regulation, synchronized and non-synchronized reserves occurred at the same time as high real-time energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreases, and system capacity competes to meet the ancillary services requirement while maintaining power balance.

Figure 19: Ancillary Service Price and Energy Price

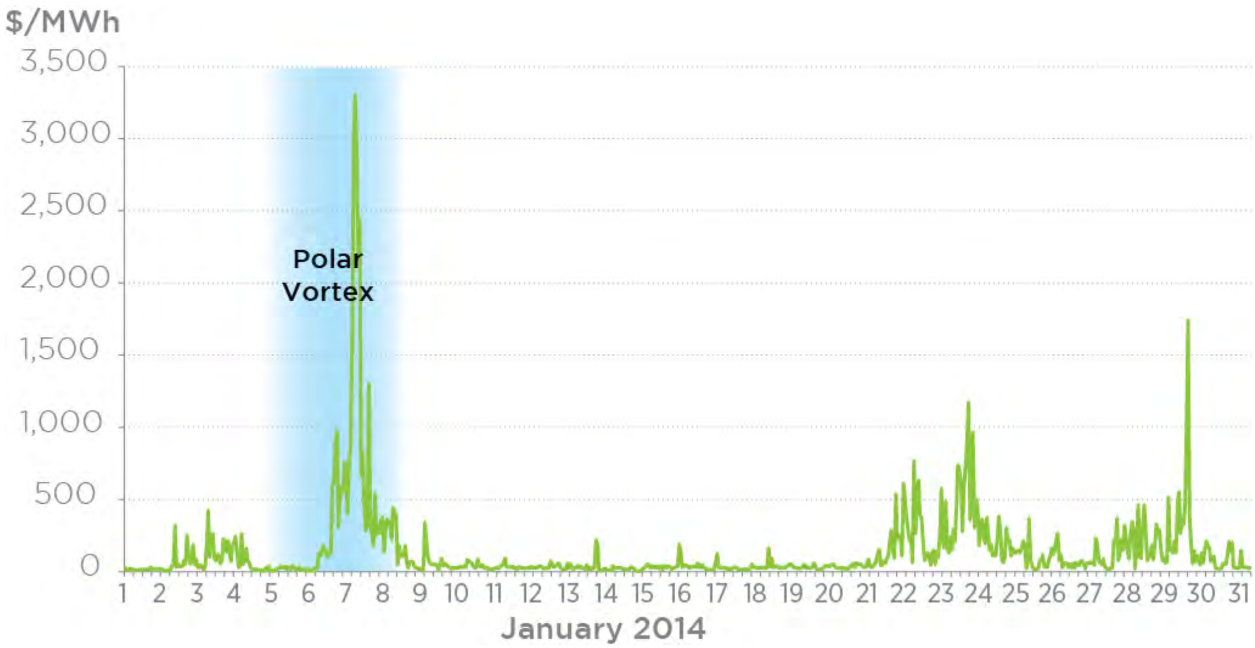


Regulation

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz.

In October 2012, PJM implemented a new market structure called Performance Based Regulation, which aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

Figure 20: Regulation Prices



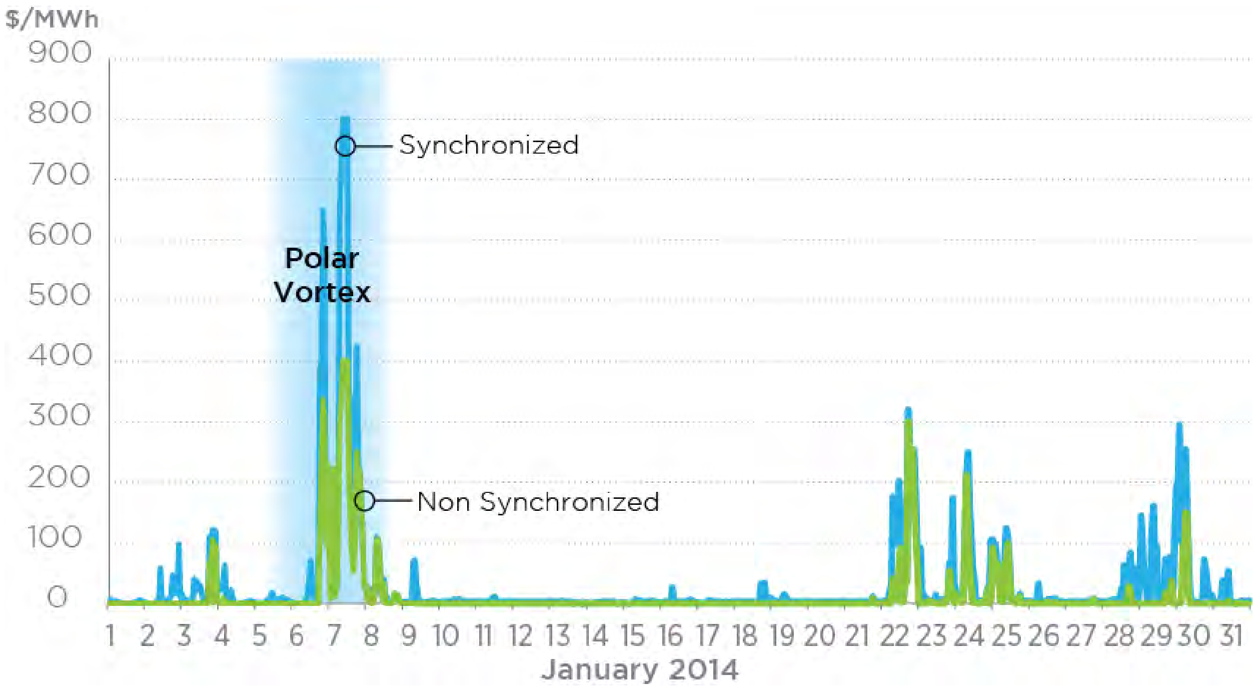
Regulation lost opportunity cost is the revenue foregone or increase in costs relative to the energy market for providing regulation service. Performance Based Regulation was designed to calculate and include resource specific regulation lost opportunity cost in the regulation market clearing price on a real-time five-minute basis (similar to real-time locational marginal prices). Real-time locational marginal prices in excess of $1,800 per megawatt-hour caused the high regulation market clearing price of $3,296 per megawatt-hour. This high price occurred as PJM triggered shortage conditions.

The regulation price spike seen during shortage pricing periods on January 6 and 7 also can be attributed to the poor performance factor in the regulation market as high-performing generators were being used for energy and reserves instead of regulation. The poorer performance factor inflates the total regulation price. Increasing the performance score requirements is discussed in the Lessons Learned and Recommendations section. The total credit paid for regulation price and lost opportunity cost not included in the regulation price was approximately $65 million for the month of January 2014.

Reserves

As displayed below, synchronized and non-synchronized reserve prices hit their maximums, $800 and $400 respectively, on January 7, 2014. These prices reflected system conditions during shortage pricing. The total Synchronous Reserve Tier One Market Price Credit and Synchronous Reserve Lost Opportunity Cost Credit was $87,890,200. Total non-synchronous reserve cost was nearly $6 million for January 2014.

Figure 21: Synchronous and Non-Synchronous Reserve Prices



Winter Storm, January 17-29

Conditions

A second, longer cold weather period in January 2014 again challenged the PJM system and operators. Prolonged cold temperatures January 17-29 came with a snow storm that dropped about a foot of snow on the East Coast. While, during the Polar Vortex, power supply issues centered on the unavailability of generation because of forced outages, during this second cold period, the key contributor to operational challenges was scheduling natural gas-fired generation to meet demand.

Having experienced the month's previous generator startup problems and a far above average 22 percent forced outage rate, PJM planned for similar generator performance as well as limits on the natural gas infrastructure. The scheduling of natural gas-fired resources became increasingly difficult through this period because of the rigid and expensive terms and conditions generators needed to accept in order to procure gas. Certain gas-fired generators notified PJM that they could get gas only if they committed to operate at a fixed output for an extended period of 24 hours or more in some cases. The fact that the period included two weekends – one of them a holiday weekend – exacerbated the fuel procurement-related situation. The timing difference between the gas and electricity markets also resulted in generation owners having to commit to buy gas before knowing whether their units would be scheduled to operate.

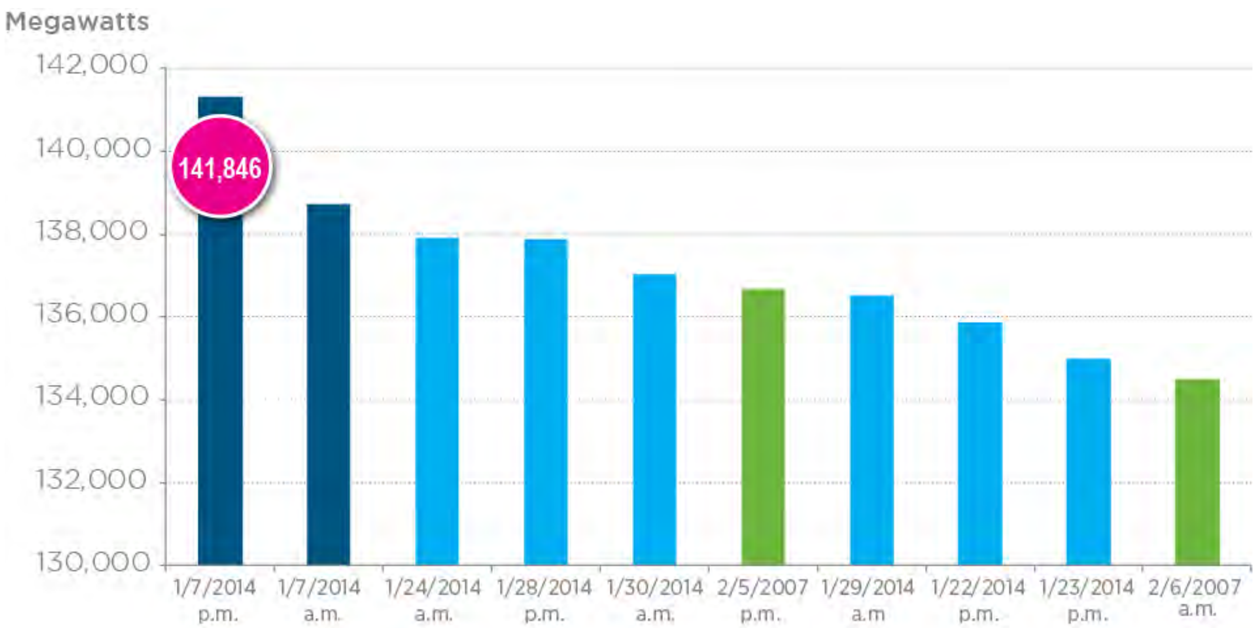
Meanwhile, spot natural gas prices soared; for example, on January 22 spot natural gas prices were 27 times the previous four months' average. Alternative fuels (usually oil) were a challenge for dual-fuel units for reasons that included fuel deliverability or minimum allowed run times because of emission limits. Because of the resource limitations, PJM made scheduling decisions without pricing certainty to ensure that sufficient resources were available to meet forecasted conditions.

Reliability was preserved during the entire month of January, but with record high out-of-market (uplift) costs. The costs were higher at the end of January because of resource fuel limitations, high natural gas prices, contractual constraints of gas units and the uncertainty of demand and of resource availability.

Weather and Load Forecast

The January 2014 Winter Storm had a more extended duration compared to the Polar Vortex earlier in the month. Extreme weather conditions were predicted during the last two weeks of January. As shown in Figure 22: , PJM reached eight of the top 10 winter peak demands in all of PJM's history in the month of January 2014. Six of these peaks were set in the later part of January during the Winter Storm.

Figure 22: Top 10 Historic Winter Peak Demands



Near-term weather projections indicated that this stretch of cold weather would be both as severe as the Polar Vortex and much longer in duration. However, when the Winter Storm dropped over a foot of snow along the East Coast, it decreased load as many people stayed home due to work and school cancellations. Because the severity and impact of storms on the population are variables that often cannot be predicted, load forecasters and system operators often cannot consider these variables when committing generation to meet the expected load and reserve requirements. As a result, more generation may be scheduled than is needed in real time if the forecasted load does not materialize, as was the case on January 21 and January 29 because of the snow storm. The market impact of this forecasting effect is discussed in Load and Weather Impact to Markets on page 51.

Operational Planning and Advanced Communications

Based on the load forecasts, PJM developed an operating strategy based on real-time operations experienced during January 6-8. The strategy anticipated high forced outage rates again and considered the amount of voluntary

Demand Response available, performance from renewables and the potential relief from a public appeal for conservation.

PJM held conference calls with transmission and generation owners as well as neighboring entities to ensure full awareness of the pending weather and the load projections. Similar to actions taken during the Polar Vortex, PJM instructed its members to take steps to ensure availability of all transmission and generation resources, which included cancelling planned outages and recalling existing outages where possible, and communicating to PJM any concerns about equipment, fuel, unit restrictions, etc. PJM requested units which could not acquire their primary fuel to switch to the alternate fuel. PJM also recognized the need to plan for an extended reliance on fuel-limited and environmentally-limited generation. To account for this need, PJM closely coordinated with generator owners to ensure fuel-limited and/or environmentally-limited units were placed into the maximum emergency generator status and then scheduled to run only when needed.

Natural Gas Markets Coordination

Because temperatures were expected to match the lows of early January, going into the Winter Storm, PJM was concerned about having sufficient generation. Low temperatures would increase the demand for electricity for heating and strain the gas pipelines serving residential heating load.

The following operators of pipelines issued critical notices restricting natural gas availability in the PJM footprint. The amount of megawatts of generation capacity in PJM which could have been impacted is in parentheses:

- ANR (TransCanada) in the Chicago area (approximately 2,550 MW)
- Columbia in Ohio and western Pennsylvania (approximately 5,460 MW)
- Dominion in Ohio, Pennsylvania, Maryland and Virginia (approximately 8,680 MW)
- Natural Gas Pipeline of America in Commonwealth Edison (approximately 1,125 MW)
- Texas Eastern in Ohio, Pennsylvania and New Jersey (approximately 2,215 MW)
- Transcontinental in Virginia; Washington, D.C.; Maryland; Delaware; Pennsylvania and New Jersey (approximately 2,310 MW)

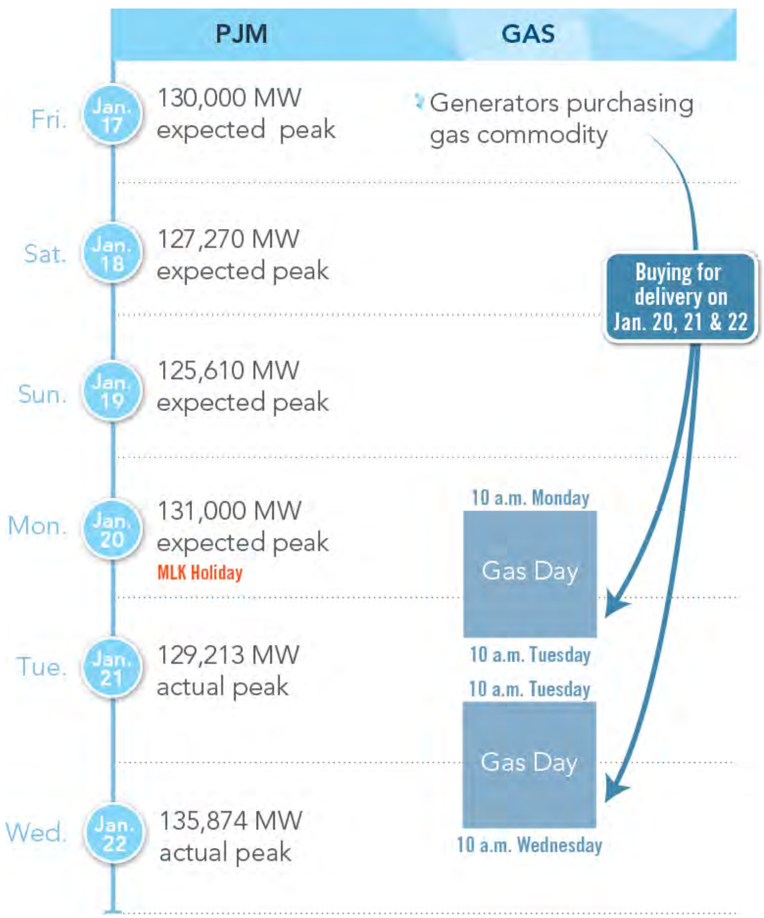
A timeline of critical notices on the natural gas pipelines in the PJM footprint can be found in

Appendix C: Natural Gas System Critical Notices.

In preparation for tighter gas conditions, PJM coordinated with gas pipelines and generation owners to ensure sufficient resources were available. A challenge with this coordination was the differences between the timing of generators' required natural gas purchase commitments and PJM's Day-Ahead Energy Market commitment timing. In some cases, gas commitments were required to be made by 9:30 a.m. EST before the natural gas day and before the PJM Day-Ahead Market commitment. Sometimes, PJM had to decide whether generators were needed without forward-looking information available on the price of natural gas, without certainty the generator ultimately would be able to procure natural gas with delivery to the plant and without certainty the plant actually would be needed as the load forecast was updated. For example, on a Friday PJM was told that natural gas would not be available for purchase by a generator throughout the weekend; therefore, PJM needed to decide whether the generator would be necessary for Monday, on the preceding Friday, so that the unit could determine whether to procure gas.

Other generation owners alerted PJM that gas marketers required them to buy a weekend package that forced PJM to run the generator through the weekend if it was needed on a Monday. Other generation owners required advanced commitments prior to the start of the natural gas day and had to buy a 24-hour package of natural gas that forced PJM to run the generators longer than needed under PJM's least-cost commitment model.

Figure 23: Natural Gas and Electricity Market Coordination Issues

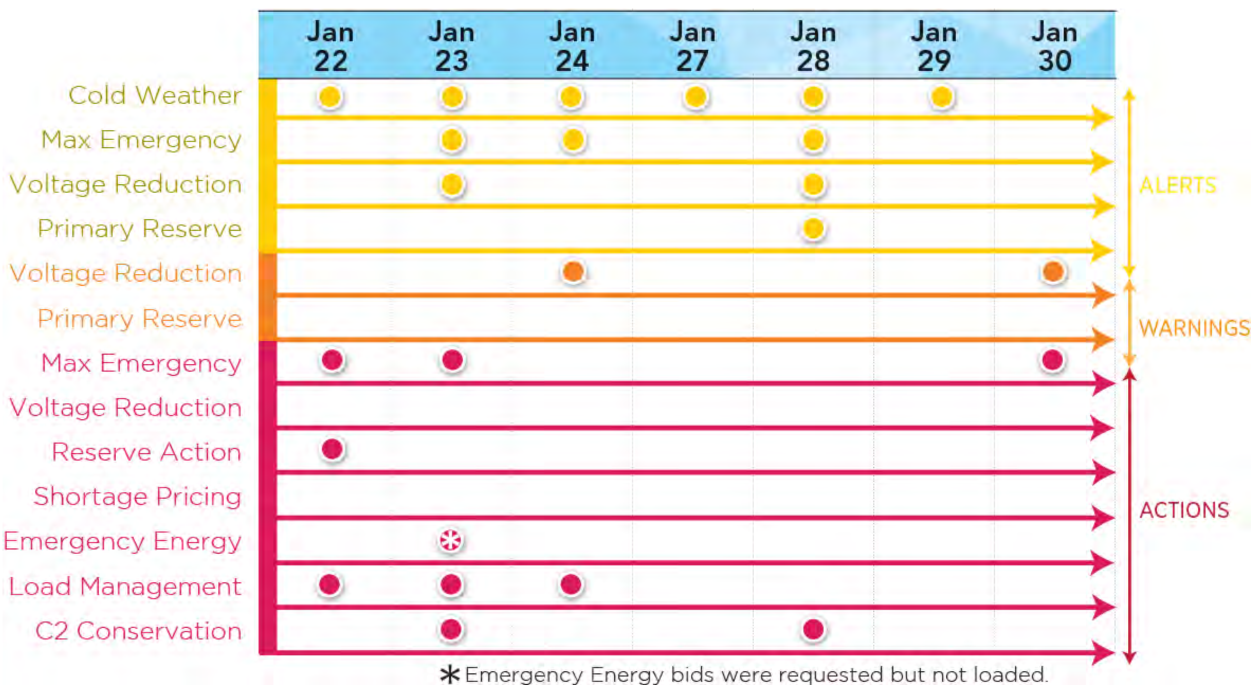


The market timing issues were further exacerbated by the three-day Martin Luther King Jr. Day holiday weekend. High electricity demand for was expected the Tuesday and Wednesday mornings after Martin Luther King Jr. Day, January 20, which coincided with the Tuesday-Wednesday 10 a.m. to 10 a.m. gas day. Generation owners told PJM that they needed to know on Friday, January 17, whether their units would be scheduled to run in order to ensure they had natural gas for Tuesday and Wednesday mornings. Although in some instances the units were needed only to cover the morning peak from about 5:00 a.m. to 9:00 a.m., the units had to buy 24 hours' worth of gas. PJM's need to make these unit/gas scheduling requests outside of the Day-Ahead Energy Market increased the level of uplift (out-of-market) payments in the latter half of January. These natural gas terms and conditions requiring multi-day commitments from generators were significantly at odds to the traditional Day-Ahead Market commitment and, along with the record high gas prices, increased the level of uplift.

Operations

In preparation for and in response to the real-time conditions, PJM issued multiple notices, alerts and emergency actions. The following figure summarized the emergency procedures that were issued for January 22 to January 30.

Figure 24: Emergency Procedures during the Winter Storm of January 2014



For the second blast of cold weather, PJM implemented many of the same actions taken prior to and during the Polar Vortex. Cold Weather Alerts were issued in advance of each operating day, and conference calls were held with members and neighbors multiple times each day to develop and adjust the operating strategy based on real-time conditions.

On Tuesday evening, January 21, the loss 1,783 MW of generation in the Baltimore Gas and Electric Company (BGE) and Pepco zones required a reassessment of generation and transmission plans for the next day. PJM's analysis identified potential thermal transmission constraints in the BGE and Pepco zones as power outside of those zones would flow into them to replace the loss of local generation. As a result of the expected transmission constraints in the BGE and Pepco zones, PJM loaded Maximum Emergency Generation at 2:00 p.m. on January 22 and called for Emergency Load Management for the two zones during for the evening peak hour. PJM also issued a Voltage Reduction Alert for the BGE and Pepco zones at 8:00 p.m.; however, an actual voltage reduction was not ordered. PJM reliably met the peak demand on January 22 without additional emergency procedures and provided shared reserves to the NYISO (117 MW at 5:36 p.m. and 73 MW at 8:56 p.m.). The day's peak demand was 135,061 MW at 7:00 p.m. At that time, 6,427 MW of interchange was being imported into PJM.

Thursday, January 23, was an even more challenging day. In addition to the constraints in the BGE and Pepco zones, higher loads than January 22 throughout the PJM footprint led to west-to-east constraints on the transmission system causing tighter capacity conditions in the PJM Mid-Atlantic Region. To meet the forecasted load given the anticipated system constraints, PJM loaded Maximum Emergency Generation at 4:30 a.m., called for voluntary Emergency Load Management and issued a NERC Alert Level 2 to inform neighbor systems that load management would be deployed, for the Mid-Atlantic Region, Dominion and the FirstEnergy South/Allegheny Power zones during the morning and evening peaks on January 23. At 4:50 a.m. PJM requested Emergency Energy bids, which was cancelled at 8:05 a.m. No emergency bids were loaded. PJM also issued a request for public conservation of power for the BGE and Pepco zones for the evening of January 23. Actual peak loads on January 23 were 132,431 MW at 8:00 a.m. and 134,302 MW at 8:00 p.m. (The forecasted loads had been 135,579 MW for 9:00 a.m. and 136,572 MW for 9:00 p.m.) Interchange into PJM during the peak hours (5,409 MW) was less than the interchange into PJM January 22, resulting in more internal resources running to meet the load.

Load and transmission constraints on Friday, January 24, were similar to January 22. Forecasted peak load was 133,902 MW at 9:00 a.m. with an actual peak load of 136,982 MW occurring at 8:00 a.m. The regional temperatures increased after the Friday morning peak. Interchange during the morning peak hour was 4,007 MW into PJM. The 1,783 MW of generation in the BGE and Pepco zones was still out though a partial return was anticipated that evening. PJM loaded Maximum Emergency Generation at 4:30 a.m., called for Emergency Load Management for the BGE and Pepco zones for the morning peak on January 24. PJM also issued a Voltage Reduction Warning at 7:20 a.m. for the BGE and PEPCO zones in anticipation of additional emergency procedures in the two zones.

The weekend of January 25-26 provided some reprieve from the cold temperature. Weekend loads typically are lower than weekday loads making operations less challenging. The return to service of 1,783 MW of generation in the BGE and Pepco zones helped alleviate west-to-east constraints previously experienced that week. However, temperatures across the region were still colder and demand higher than normal. While the peak on Saturday, January 25 was 118,275 MW and 114,006 MW on Sunday January 26, typical winter weekend peaks are around 90,000 MW.

On Monday, January 27, a Cold Weather Alert was the only emergency procedure issued. Although the forecasted peak demand for January 27 was 131,825 MW, the actual peak demand was lower, at 126,379 MW at 8:00 p.m. Total interchange into PJM during the peak was 3,640 MW.

Despite the lower demand on Monday, demand for Tuesday, was projected to be similar to January 7, when PJM set its all-time winter peak of 141,846 MW. Load forecasts for Tuesday, January 28, were 137,663 MW at 9:00 a.m. and 140,411 MW at 9:00 p.m. To prepare for Tuesday's expected high demand, PJM on Monday issued a Cold Weather Alert, a Maximum Emergency Generation Alert, a Voltage Reduction Alert, a Primary Reserve Alert and requested public conservation of power on Tuesday. All these emergency procedures were used on January 7 to successfully meet the record demand.

However, actual demand was less than forecasted on January 28, and generating resources performed better than expected with an 11 percent forced outage rate (compared to 22 percent on January 7). Interchange during the evening peak was 6,504 MW. Actual system loads were 133,137 MW at 9:00 a.m. and 137,336 MW at 7:00 p.m. As a result, no additional emergency procedures were needed that day.

The weather and load for the January 29 did not require any procedures beyond a Cold Weather Alert. Forecasted peak load on January 29 was 133,823 MW at 9:00 a.m., and the actual peak load was 136,020 MW at 9:00 a.m. Interchange during the morning peak was 4,722 MW.

After the peak the evening of January 29 and during the overnight period, 1,370 MW of generation across the system were unavailable. With cold temperatures forecast to linger, PJM on the morning of January 30 loaded Maximum Emergency Generation in the BGE and Pepco zones and issued a Voltage Reduction Warning for the rest of the system. The primary concern in the BGE and Pepco zones was thermal constraints. All available resources in those zones were committed via the Maximum Emergency Generation action to control for those constraints. Following the morning peak, temperatures moderated, and system conditions returned to normal. Forecasted peak demand for January 30 was 131,965 MW at 9:00 a.m., and the actual peak demand was 136,215 MW at 8:00 a.m. Interchange during the peak was 4,330 MW into PJM.

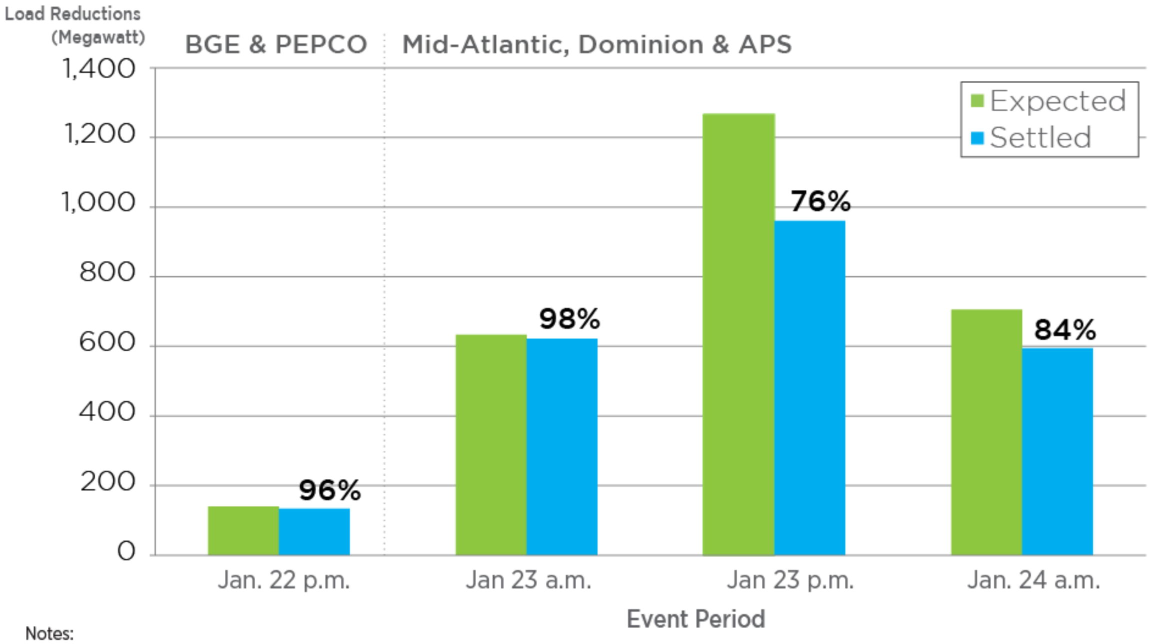
Demand Response

Demand response during the Winter Storm was used to reduce peak loads in some eastern areas rather than for the entire region as it was during the Polar Vortex. This was due in part to issues with transfers, MW flows across the transmission paths within PJM, and units tripping offline. During the Winter Storm, PJM called on demand response four times to handle with issues with transfers, transmission limits and generating units shutting down:

- January 22 for the evening peak in the Baltimore Gas and Electric Company and Pepco zones
- January 23 for the morning peak in the Mid-Atlantic Region, Dominion Zone and Allegheny Power System Zone
- January 23 for the evening peak in the Mid-Atlantic Region, Dominion Zone and Allegheny Power System Zone
- On January 24 for the Mid-Atlantic, Dominion and Allegheny Power System (APS) zones.

Demand resources were not obligated to respond to these requests because they were made outside of the June 1 - September 30 mandatory demand resource response compliance windows. Regardless, many demand response resources answered the calls for reduction.

Figure 25: Demand Response during the Winter Storm

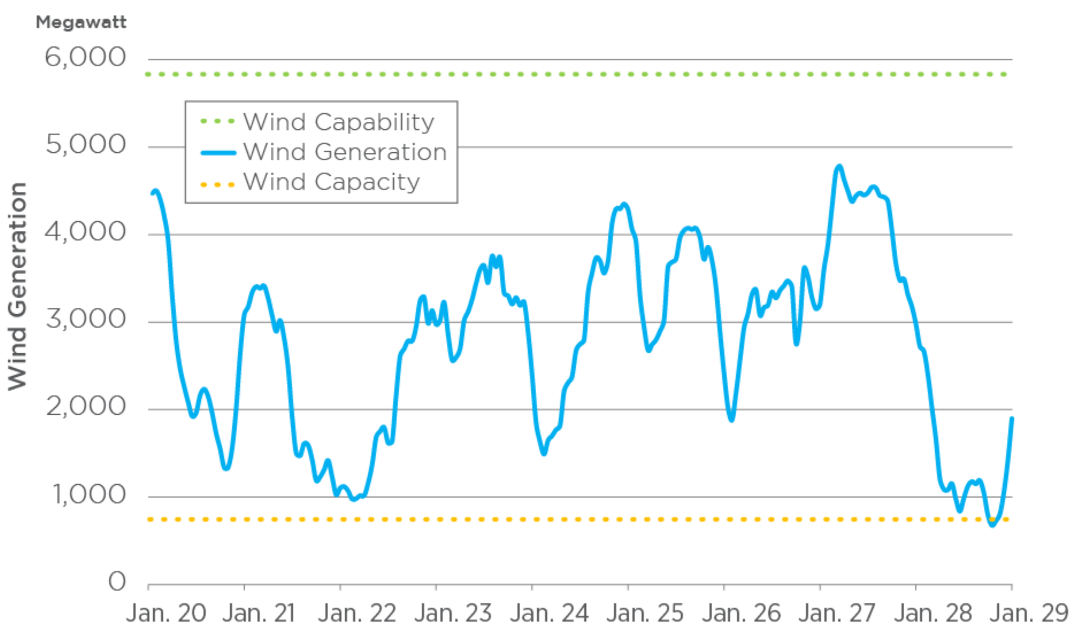


Notes:
1. DR events dispatched during non-compliance period.
2. Expected Energy Load Reductions (MW) - CSP reported estimate based on current market rule.
3. MW value is average hourly load reduction for non-ramp in hours.

Operational Observations and Challenges

Similar to operations during the Polar Vortex, some variables exceeded PJM's expectations. Demand response's availability and response was one of those variables. The requests to the general public for conservation again were considered to have had a positive impact. Wind power again produced at a level above the calculated annual wind capacity during the January 20-29 timeframe.

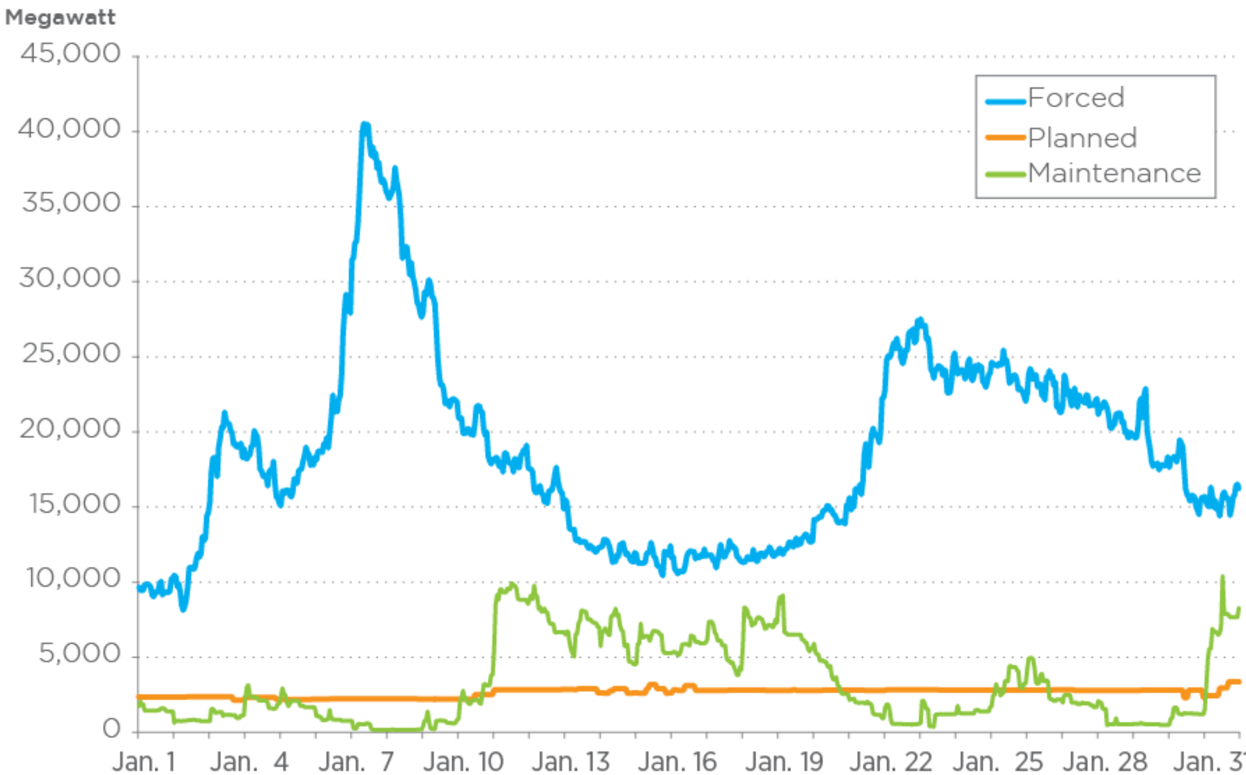
Figure 26: Winter Storm Wind Generation



Generator Performance: Outages

Because PJM experienced a 22 percent generation forced outage rate on January 7, similar forced outage rates were expected during the Winter Storm because of the similar forecasted weather conditions. The amount of generation available during the Winter Storm improved as compared to the Polar Vortex but was still worse than PJM's historical average winter forced outage rate.

Figure 27: Generator Outages – January 2014



PJM also coordinated with generator owners to manage available run hours based on fuel inventories. PJM and generators that could still run on oil communicated to maintain awareness of the generator's status and possible issues.

Generation Performance: Fuel Limitations

Some gas-fired units have the capability to use an alternate fuel (dual-fuel capability), which increases flexibility when gas supply becomes tight. The predominant alternate fuel is oil. While dual-fuel units increase flexibility, there were still challenges operating the units on oil. PJM requested dual-fuel generation owners unable to secure gas to operate their units on oil during the extremely cold weather events. Even with this flexibility, generation owners encountered issues including run-time limits related to permit-defined environmental restrictions, resupply challenges and increased failure rates for unit startup. Units that switch to oil operate with increased emissions, which limits their maximum run times due to environmental constraints. In other cases, units operating on oil may have had only limited ability to make and store demineralized water for the injection systems that must be operated to reduce nitrogen oxide emissions when running on oil. PJM coordinated with generation owners that needed to decrease the maximum run time per day for their units in order to conserve emission credits. Identification and tracking of fuel limitations was done manually by PJM and the generator owners. There were approximately 1,000 MW of generation with decreased run times for emission reasons.

The increase in demand for oil caused another challenge for generation owners. Many units in the Northeast switched to oil as gas became unavailable increasing demand for oil. In some cases, oil suppliers began to run low on inventory or deliveries were slow because increased demand was unexpected and available delivery trucks were limited. Generation owners found it difficult to keep oil tanks full on a daily basis and had to limit run hours for their units. There were approximately 2,000-3,000 MW of generation affected by oil supply and delivery issues. Also, generating units running on oil have an increased failure-to-start rate due to clogged fuel lines.

Contractual Constraints

During January PJM used the Day-Ahead Market, load forecasts and the experience of generation outages earlier in the month to schedule the necessary resources for reliable operations. Contractual constraints on generators' availability challenged PJM operators and contributed to the January uplift that will be discussed in the Market Outcomes: Winter Storm section below. The contractual constraints included natural gas generators with:

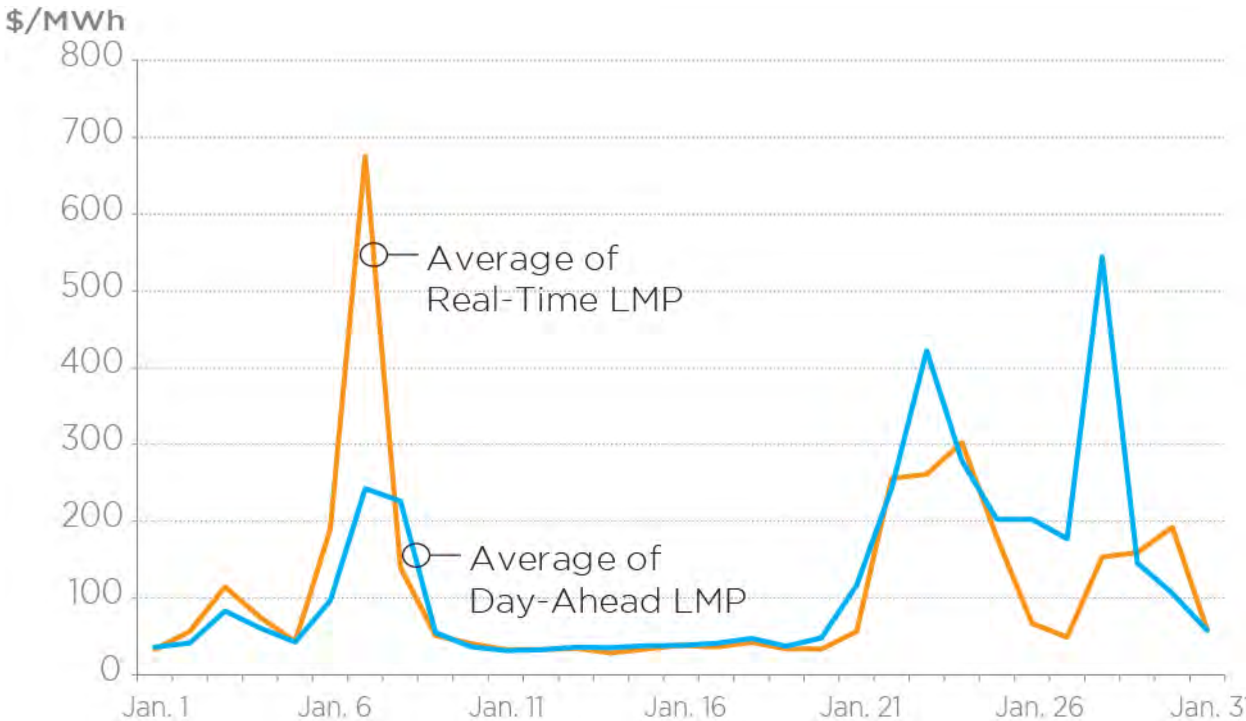
- the need for early commitment, days ahead of the Day-Ahead Energy Market, to ensure fuel deliverability;
- inflexible scheduling criteria such as 24-hour and multi-day commitment; and,
- purchase of gas for an entire weekend.

Market Outcomes: Winter Storm

Energy Prices

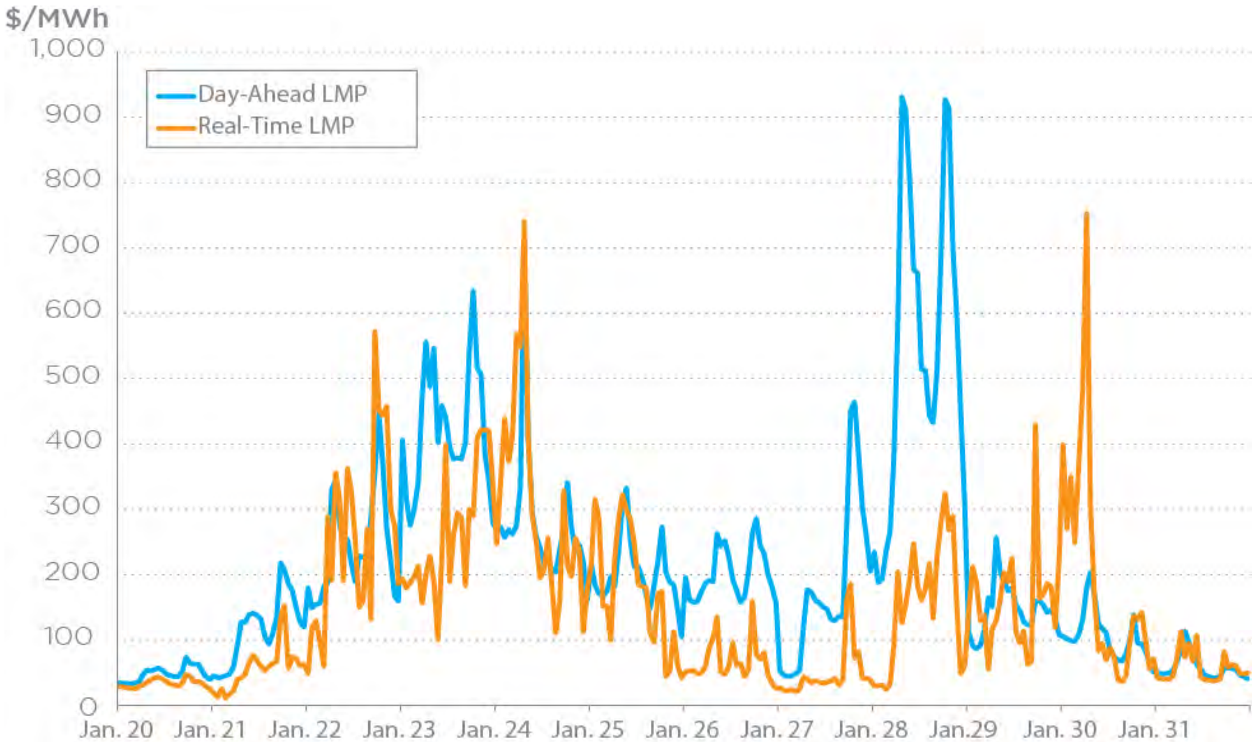
Energy prices were high during the Winter Storm but not as high as during the Polar Vortex. Shortage pricing conditions were not present during the Winter Storm because sufficient generation was available to meet the forecasted demand. Day-Ahead Energy Market prices were higher than real-time prices during the Winter Storm. The price difference resulted in part from PJM's scheduling of resources to ensure that primary and synchronous reserve requirements were met throughout the Winter Storm while taking into consideration the uncertainties surrounding whether loads, interchange, generation availability and natural gas/electric coordination issues would occur as did earlier in the month.

Figure 28: Average of Real-Time and Day-Ahead Locational Marginal Prices – January 2014



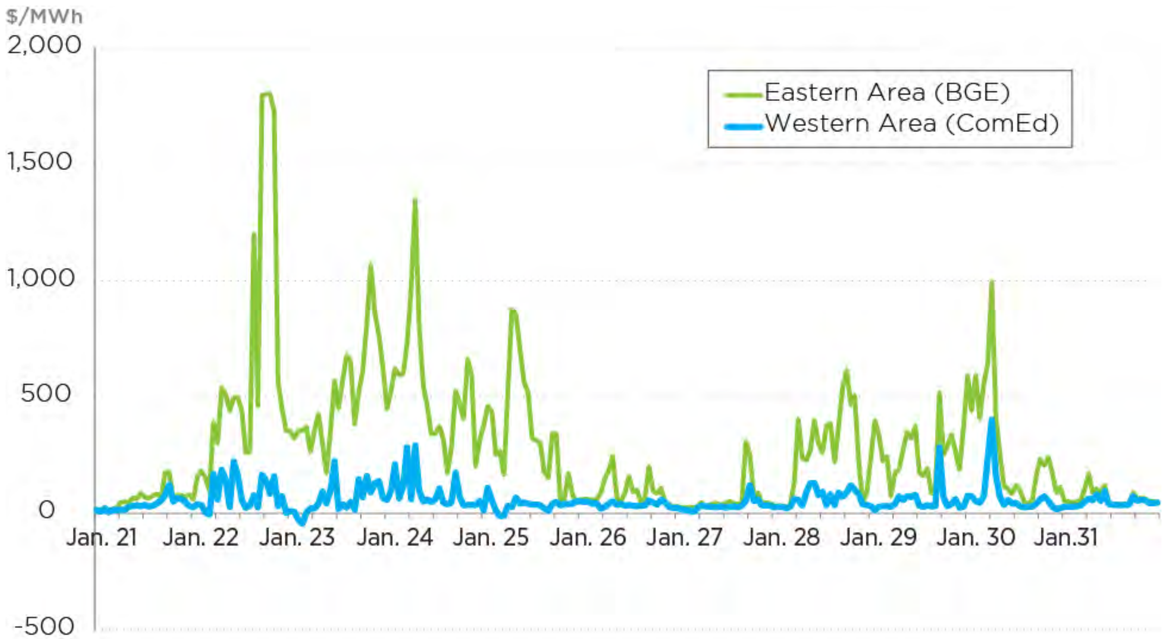
During January 22-25 real-time and day-ahead prices were more closely aligned. During January 27-29, day-ahead prices were higher than real-time prices – an indication of market participants' expectation that conditions would follow the Polar Vortex pattern. Real-time LMPs were lower than day-ahead LMPs due to the mix of 24-hour burn gas units and a better than expected generator forced outage rate. January 30 real-time LMPs exceeded day-ahead prices.

Figure 29: Real-Time and Day-Ahead Locational Marginal Prices during the Winter Storm



Real-time prices were lower in PJM's western area compared to the eastern area due to fewer transfer interface constraints during the Winter Storm than during the Polar Vortex. Eastern zones had more combined-cycle generators fueled by natural gas on the margin resulting in higher prices in the eastern zone than in the western zone. During the Winter Storm, there was variability in temperatures across the region compared to the Polar Vortex, which had persistent, extreme cold across the entire footprint. In preparation for anticipated high forced outages as experienced during the Polar Vortex, PJM called on additional generation in the eastern portion of the footprint. The following chart displays the difference between LMPs in the east versus west.

Figure 30: Eastern and Western Locational Marginal Prices



Locational marginal prices are calculated in five-minute intervals with generation typically being the marginal resource that sets prices. On January 24, demand response set prices for seven five-minute intervals. Additional information on interval analysis of prices can be found in the Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals.

Natural Gas Prices and Offer Caps

The PJM Operating Agreement[18] requires all generation capacity resources in PJM that have been committed as capacity to submit offers into the Day-Ahead Energy Market. The Operating Agreement also limits generation offers into the Day-Ahead Energy Market to $1,000/MWh.

These two provisions had not come into potential conflict before January 2014. To PJM's knowledge, sellers with generation resources offering into PJM's energy market have not had marginal costs in excess of $1,000/MWh or have not notified PJM of their situation. However, it became an issue when natural gas prices spiked with trades on January 21 and delivery on January 22 averaging over $120/MMBtu (and prices as high as $140/MMBtu for the day of delivery) – record-setting gas prices for the PJM footprint. The result of the high gas prices was electricity generation costs that could exceed the $1,000/MWh offer cap. For example, for a combustion turbine in the PJM region with a roughly average 10,000 Btu/kWh heat rate, $120/MMBtu translates to a $1,200/MWh cost to produce energy, ignoring any additional costs such as operations and maintenance.

On January 23, PJM filed with the FERC a waiver of certain provisions of the Operating Agreement in order to allow for make-whole payments for the difference between the capped price and the marginal costs for generating energy that exceeded the $1,000/MWh cap. In a companion filing, PJM requested approval by February 10 to allow cost-based offers to exceed the $1,000/MWh offer-price cap. The FERC approved both waivers.

18 at Schedule 1, section 1.10.1A(d)

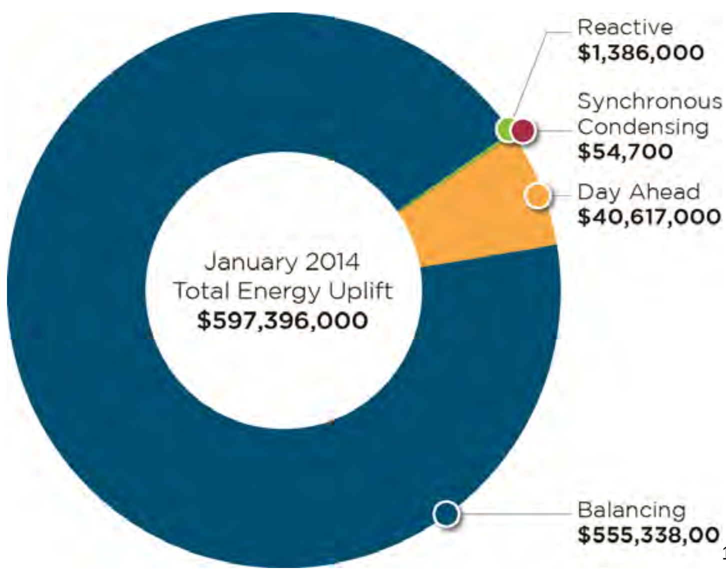
Uplift

PJM expected the possibility of generator outages similar to those experienced in the Polar Vortex and scheduled generation accordingly to ensure reliable operations during the Winter Storm. The lessons learned from the Polar Vortex were to get natural gas generation online early and keep it online. However, the later part of January had less extreme weather and better generation performance coupled with inflexible run times and high fuel prices for natural gas-fired generation, which led to uplift/operating reserve costs. Uplift costs were extremely high at the end of January as PJM scheduled sufficient generation to supply consumers and ensure adequate operating reserves to mitigate risk from unscheduled generator outages, volatile interchange and natural gas uncertainty.

To incent generators and demand resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM 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 following PJM's direction. Generators told PJM that, because of gas market constraints, their gas-fired resources in some cases had to be operated at full output each hour and for a longer duration than PJM required them – which created extremely high uplift costs especially because of the extremely high prices for natural gas.

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

Figure 31: Uplift Breakdown



[19], [20]

A majority of the uplift cost in January, as shown above, was due to generators scheduled by PJM running in real-time to meet reliability needs.

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[19] Balancing includes lost opportunity cost, the difference between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.

[20] Day-ahead uplift includes black start make whole payments for Automatic Load Rejection units and reactive credits.

There can be various scenarios in which market revenues are insufficient to cover generators' costs. The drivers that contributed to high levels of uplift in January 2014 included:

- Natural Gas Prices – High natural gas prices exacerbated the cost of uplift as the units operating at PJM's direction were more expensive than there historical costs.
- Contractual Constraints – Due to restrictions on natural gas deliveries, many resources required PJM to maintain strict megawatt output levels during periods when they were uneconomic to ensure they were available during peak conditions. Additionally, the lack of alignment between the gas and electric day timing often required PJM to commit to running gas units prior to the PJM Day-Ahead Energy Market.
- Prudent Operations – During January, PJM committed resources for expected extreme system conditions. Such operations are typical during Cold Weather Alerts, resulting in the scheduling of additional reserves to account for increased forced outage rates as identified in the PJM Emergency Operations Manual. As a result, more expensive units displaced lower-cost resources and sometimes suppressed locational marginal prices. Throughout January, and particularly early in the month, PJM experienced higher generator outage rates than had ever been observed. PJM needed to schedule additional generation to be available to mitigate any potential power shortfalls due to generator forced outages.
- Interchange Volatility – Variable imports and exports of energy, which reacted to PJM energy prices, affected locational marginal prices and commitment decisions by PJM. The amount of power imported is difficult for PJM to forecast and is not under PJM's control; therefore, PJM must schedule internal resources to ensure adequate generation is available.

In the current PJM market design, if a generation resource follows PJM's commitment and dispatch, that generator is guaranteed to fully recover its costs for the hours it runs at PJM's direction. Operating reserve payments are designed so resource owners are incented to follow PJM direction to help maintain control of the grid in the most efficient manner possible and also ensure adequate operating supply plus additional capability for reserves. Day-ahead and real-time operating reserve credits are paid to resource owners; these credits are paid by PJM market participants as operating reserve charges. Operating reserve charges are not part of the energy market price signals as they are based on calculations from data that is not all available on a real-time basis.

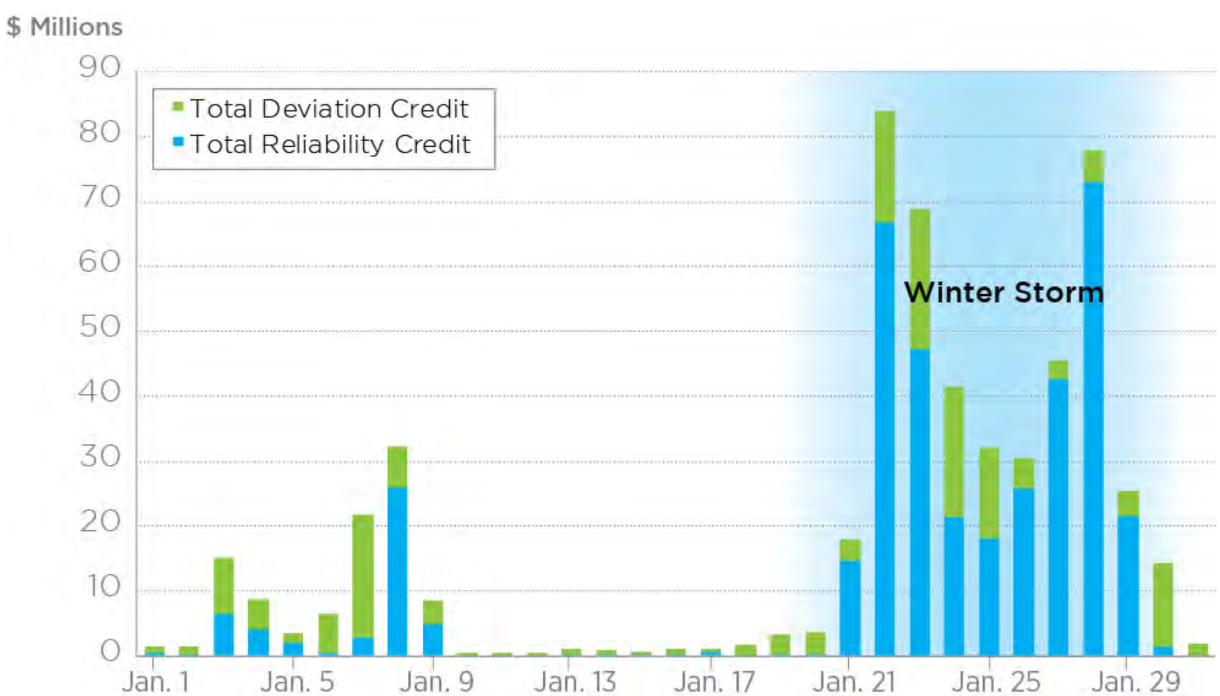
Increased operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid. The uplift costs are high when the primary fuel of additional generation being run is high priced. During the Winter Storm, generation was needed specifically in the northeastern section of PJM where there is a large amount of natural gas-fired generation. Operating reserve payments increased when the additional generation being run was inflexible due to 24-hour gas burn requirements. Due to the tight supplies in the natural gas market, many PJM generators were kept on-line to mitigate the risk of not being able to obtain natural gas after shutting down. Some of these generators were run overnight because they could not shut down and re-start again due to fuel or weather issues.

Figure 32: Balancing Operating Reserve Credits

Reliability Credit	Generator committed in advance of the operating day and outside of the Day-Ahead Market. Generator committed during the operating day and is out of the economic merit order.
Deviation Credit	Generator is needed to meet anticipated load plus reserves. Generator is committed during the operating day and cost is greater than locational marginal prices most of the time.

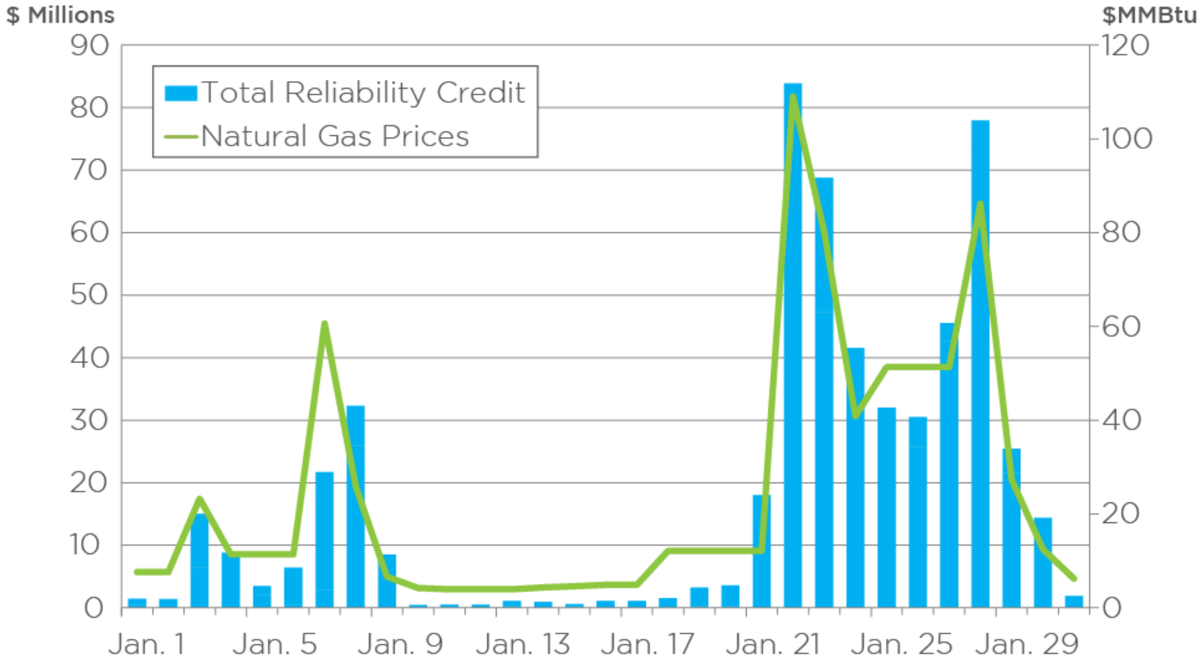
There are two general types of balancing operating reserve charges. If a generator is called to run after the close of the Day-Ahead Market and during the Reliability Assessment Commitment performed after the Day-Ahead Market results are posted, it is dispatched either for prudent operations or “load plus reserves.” If a generator is dispatched for prudent operations, then the uplift cost associated with the generator running is categorized as a reliability credit. If a generator is needed for load plus reserves, then its uplift cost is categorized as a deviation credit. When a generator is committed to run during the operating day, if its cost is greater than locational marginal prices most of the time, the uplift credit for the generator also is categorized as a deviation credit. During the operating day, if a generator is not economical (i.e. its cost-based offer is higher than the current LMP), then its associated uplift cost is categorized as a reliability credit.

Figure 33: Balancing Operating Reserve Credits for Deviation and Reliability



The overwhelming majority of balancing operating reserve credits during the Winter Storm was for reliability credits. Overlaying the natural gas prices on top of just the reliability credits demonstrates the impact on the uplift costs of the high natural gas prices, which were exacerbated by contractual constraints.

Figure 34: Reliability Credits vs. Natural Gas Prices

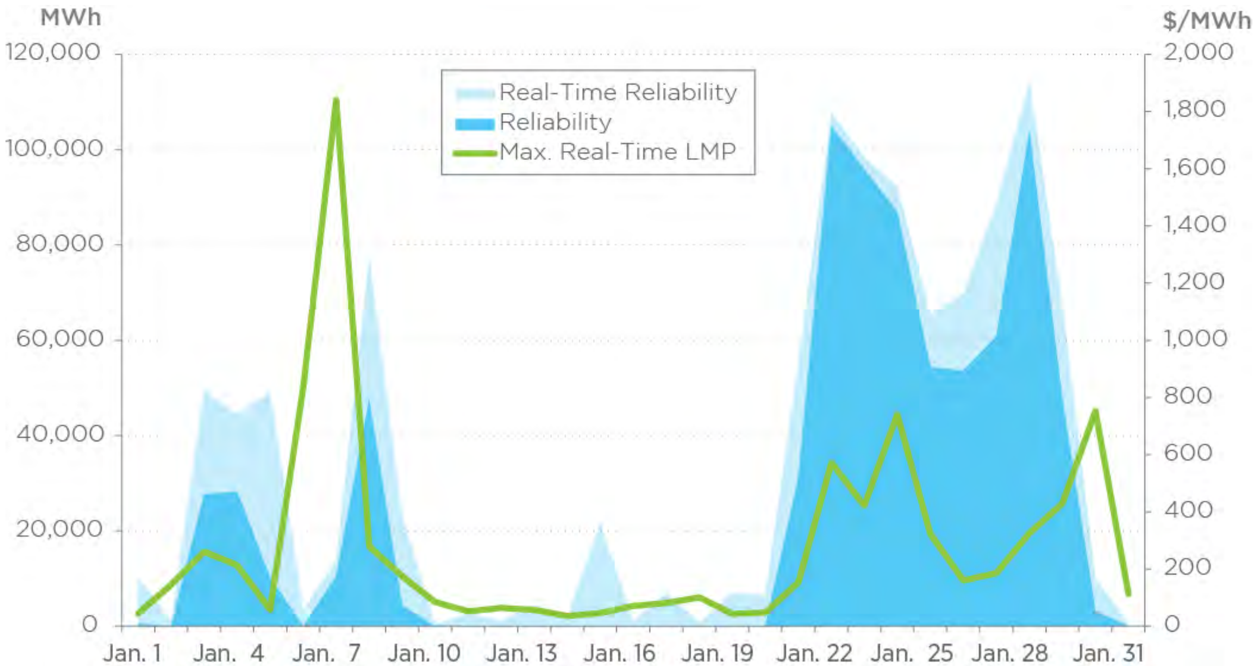


PJM worked in advance of the Winter Storm to mitigate the risk of losing generators and worked with generators which had inflexible parameters to keep them online to ensure reliability would be maintained. An example of inflexible parameters is a long minimum run time. PJM may need a generator only for three hours but must keep it online for the full minimum run time of the resource. The minimum run time constraints can impact uplift costs if a generator is needed for both the morning and evening peaks and is unable to turn off between the peaks. A generator reports to PJM how long it needs to run to not damage the generator (minimum run time), how long it needs to stay off once shut down to not damage the generator (minimum downtime), and how long it needs to know in advance when PJM will needs it online (time to start). During the Polar Vortex and Winter Storm, many generators that can typically operate very flexibly had to operate on significantly more restrictive parameters due to their contractual arrangements for natural gas. Many of natural gas-fired generators had only 24-hour burn offers and, in some cases, 72-hour burn offers due to natural gas terms and conditions.

PJM scheduled generation resources during January using the Day Ahead Market and Reliability Run but also scheduled resources manually to cover forecasted load and generation outage levels experienced earlier in the month. Generators warned that they likely would not be able to procure gas without some certainty on their commitment period in advance of the typical scheduling windows and some accounting for extraordinary scheduling restrictions such as 24-hour ratable takes and multi-day commitments. Often, operators were forced to commit to these units several days in advance to ensure a reliable level of unit commitment prior to the close of the day-ahead market.

The PJM procedures used to make such commitments include section 3.2 of the Emergency Operations Manual and Section 1 of the Transmission Operations Manual. These sections document the conditions and procedures for conservative operations. The procedure includes steps such as increasing margins on reactive interfaces, and scheduling additional generation in the event of significant loss of system resources. PJM provides tools for the system operators to log these steps and subsequently allocate the costs.

Figure 35: Balancing Operating Reserve Megawatt-hours and Locational Marginal Prices in January



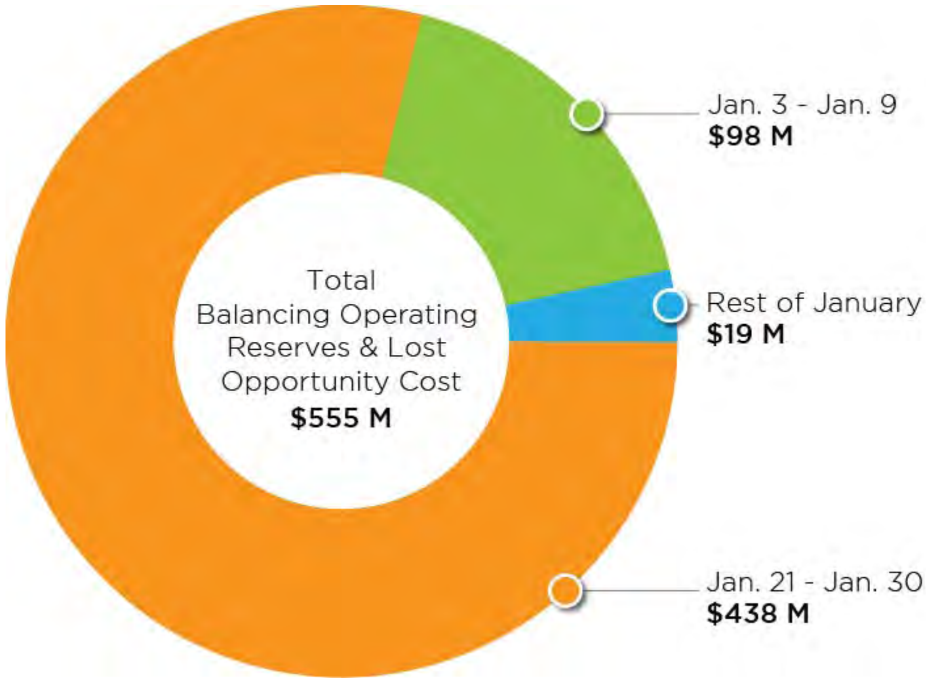
The megawatt-hours associated with real-time reliability credits are shown in the light blue added on top of the megawatt-hours committed prior to the operating day, which are represented in dark blue. The maximum real-time locational marginal price is shown by the green line overlaid on the reliability energy.

In the early part of January, the marginal resources setting the energy market prices had very high offer prices. This period of the month included a period of significantly high prices on the evening of January 6 when PJM initiated a system-wide Voltage Reduction Action, which triggered setting energy and reserve prices consistent with shortages of all reserve products. This Voltage Reduction Action resulted in LMPs in excess of $1,000/MWh that evening. Additionally, PJM deployed emergency demand response resources during the morning and evening periods of January 7. During the morning peak period on January 7, emergency demand resources set LMPs across PJM near $1,800/MWh. Similar system conditions occurred the same evening but for a much shorter period of time due to the increase in interchange.

In the latter part of January, PJM scheduled generation based on the load forecast and expected generation outages. But the inflexible terms and conditions of natural gas supplies caused generators operating on 24-burn minimums to have extremely high offer prices compared to lower-cost resources that set locational marginal prices. Although PJM deployed emergency demand resources during the latter portion of the month, they were not marginal as frequently during this period and, therefore, did not produce the high LMPs seen earlier in the month.

If a generator, such as the gas-fired generators with inflexible supplies, is required to run and would not be the next economic megawatt that PJM would dispatch, the generator will not set locational marginal prices. If the cost of the generator's power is much greater than locational marginal prices, then the generator displaces less-expensive resources. Therefore, these inflexible, expensive megawatts depressed prices, making the system even more uneconomical.

Figure 36: Balancing Operating Reserve Credit by Storm



A majority of the real-time or balancing operating reserve and lost opportunity cost expense was during the winter storm in the latter half of the month.

In summary, operating reserve costs were higher at the end of January because PJM had to commit resources which were both inflexible and expensive in order to maintain reliability and mitigate risk from unscheduled generator outages and natural gas terms and conditions.

Contractual Constraints

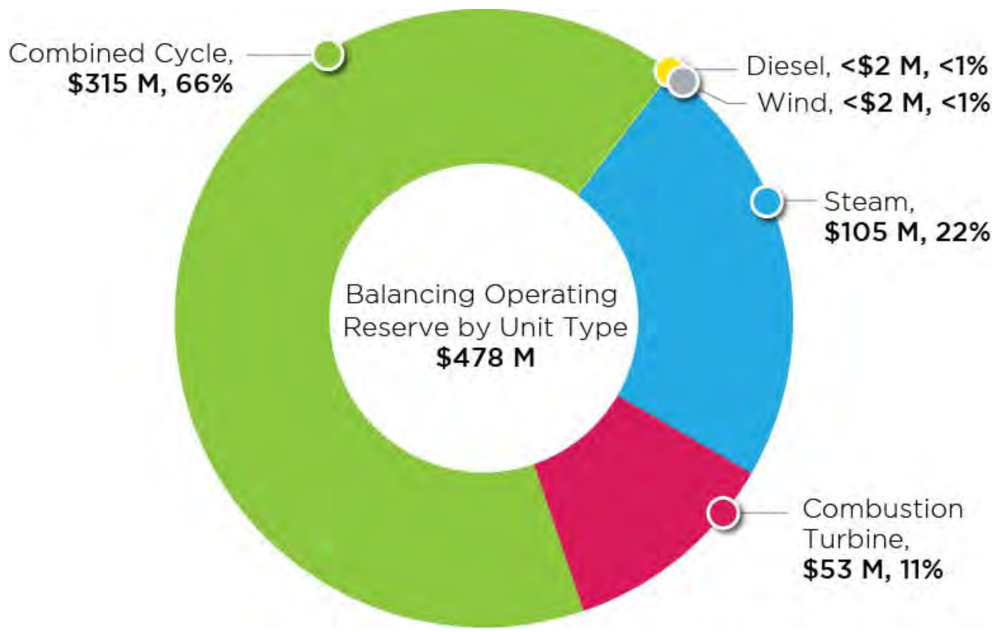
PJM works to run as few units as possible and minimize production cost, but operational parameters of individual generation units can limit flexibility. One reason for increased generation contractual constraints during January was natural gas pipeline operational orders. During January 2014 peak natural-gas demand days[21] some pipeline operators required customers, including generators, to take natural gas from their systems in even, incremental amounts over a 24-hour natural gas day, 10:00 a.m. to 10:00 a.m. This process forced generators to run during periods when they traditionally would be uneconomic; the generators must run or face significant operational or economic penalties.

Generator limitations are based on unit type and operational capability and can include issues such as fuel procurement and environmental limitations. Generators are scheduled economically, but, due to the generator's minimum run time or other limiting parameter, it must be run uneconomically through some hours before it can be shut down. When controlling the grid in January, PJM ran additional generation that was relatively inflexible because

21 Peak gas demand days: January 6-8, 21-23, and 27-28

of the operational issues highlighted above. These generators could not cycle on and off from hour to hour and were kept online through the overnight and uneconomic periods in order to be available during peak electricity demand hours.

Figure 37: Balancing Operating Reserve by Generator Type



The majority of the balancing operating reserves payments went to combined-cycle generators[22]. Much of the uplift to combined-cycle generators was due to limitations on the types of natural gas contracts that could be procured during the storm. Some combined-cycle generator owners told PJM that to ensure their availability they would need to run 24 hours.

Interchange Impact to Markets

Electricity flowing into or out of PJM from neighboring areas, known as interchange, also can lead to uplift when it differs significantly from the expectation PJM operators use to schedule and dispatch resources to maintain reliability. An interchange transaction can either be an import, meaning power is purchased from a neighboring area and sold into PJM, or an export, where power is purchased from PJM and sold in an external area. These transactions can be submitted with as little as 20 minutes notice and are only curtailed or limited due to reliability concerns. In contrast, deploying emergency demand response under today's rules requires upto two hours' notice. This timing difference creates a situation in which system operators must forecast an expected amount of interchange and then operate the system based on that expectation. When that expectation significantly differs from actual system conditions, it can create uplift.

For example, on January 7 at 2:00 p.m. PJM identified the need for emergency demand response and all available generation at the evening peak based on its load forecast, generator availability and an expectation of receiving 5,600 MW of power imports from neighboring areas during the evening peak. However, during the evening peak,

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[22] Combined-cycle plants are natural gas-fired generators that typically consist of one or more combustion turbines that exhaust into a steam generator. Combined-cycle generators usually are larger and can produce more megawatts than individual combustion turbines alone; they also are generally used throughout the day and not just to generate during the peaks like a combustion turbine would be used.

PJM actually received in excess 8,600 MW of power imports from all neighboring areas. The energy being delivered to PJM above the amount anticpated was roughly equivalent to three nuclear plants and exceeded the total amount of emergency demand response that responded that evening. To maintain system control with the excess power imports, PJM ramped down conventional generating units in order to balance supply and demand, which resulted in lower LMPs across the system. Despite the low LMPs on the system, PJM still ran high-priced supply resources, including gas generation and emergency demand response, in order to meet the minimum run-time requirements on such resources. The combination of low LMPs when expensive supply resources are being run at PJM's direction required make whole payments, and, thus, creating uplift charges.

Load and Weather Impact to Markets

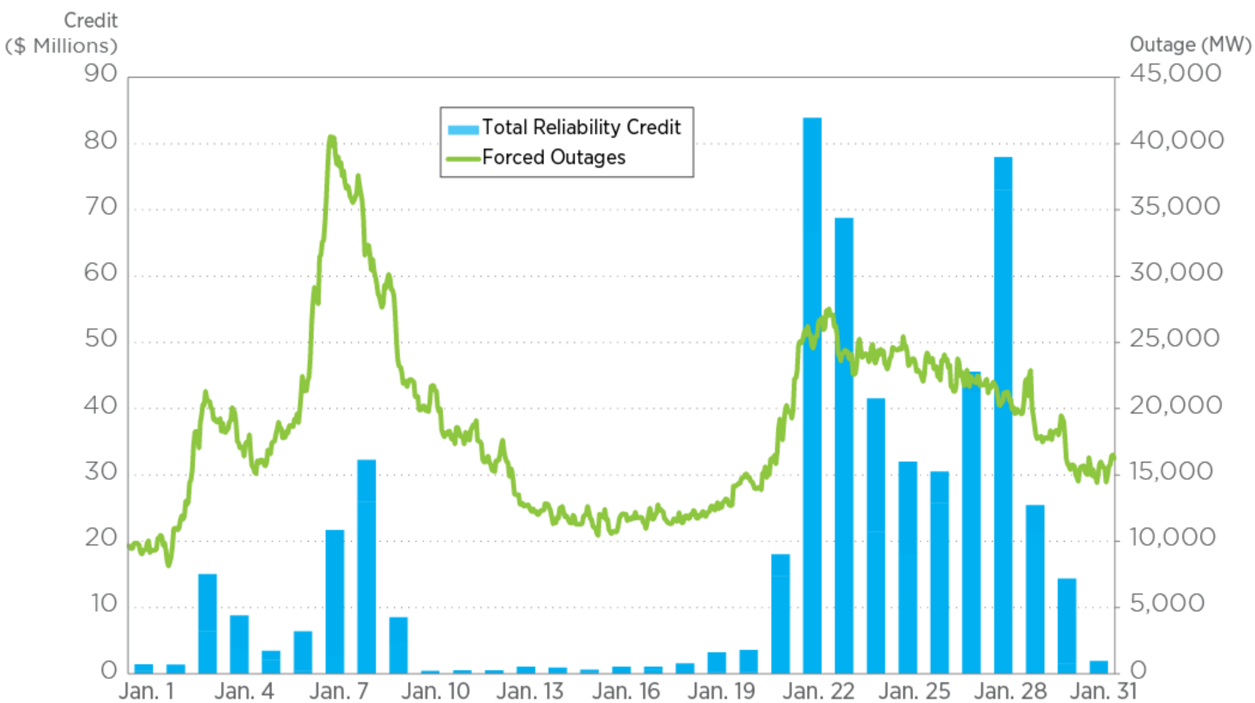
PJM forecasts both load and weather to accurately anticipate power supply needs. In extreme conditions as in January 2014, the accuracy of the load forecast is especially important. Wintertime load forecasting is even more difficult because each day has two peak load periods, morning and evening. Triggers, such as the temperature forecast changing by 7-10 degrees from one day to the next, cause PJM load forecasters and operators to reanalyze and update the load forecast. This updated forecast may necessitate scheduling additional generation, which can increase uplift if the scheduled units are not flexible or the forecast is not accurate.

Figure 38: Forecast and Actual Peak Load

Generator Outages

Generating units that do not perform on peak days are assessed performance penalties that affect current year capacity revenues. An explanation of these penalties is in Appendix D: Peak-Hour Period Availability Assessment. The total estimated Daily Peak-Hour Period Availability Charges before the January outage events were $45,586 and including January 2014 increased to $112,388.

Figure 39: Forced Outages and Balancing Operating Reserve Cost



Lessons Learned and Recommendations

In December 2013 PJM published *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave.*[23] The events of January 2014 provided PJM additional opportunities to build on some of the September 2013 lessons learned and to further enhance several areas in preparation for future winter and summer operations.

ID	Category	Recommendation	Type	Status
1	Unit Performance	PJM, in conjunction with members, should consider the following topics and develop adjustments to improve unit performance: 1. Review the penalties for non-performance during peak days and/or days when emergency procedures are issued for capacity emergencies 2. Review incentives for performance during peak days 3. Investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability 4. Review generator outage rates outlined in PJM Manual 13: Emergency Operations.	Market Construct	New
2	Unit Characteristics	Work with generation owners to identify opportunities to create or improve information sharing. Consider including the following: 1. Sharing of fuel source and emission limitations by schedule submitted and fuel limitations/certainty of supply 2. Streamlining and standardizing the outage cause types in eDart with additional specificity that provides more insight and consider methods for validation 3. Clarify the rules by which a generator can claim an Outside Management Control event for taking an outage	Process Change or Addition Technology	In progress – follow-up from Fall 2013 generator survey
3	Gas/Electric Coordination	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate industry recommendations and PJM rule changes: 1. Investigate opportunities for better harmonization of the timing of the gas and electric operating days 2. Consider potential market rule changes that would allow generators to better include natural gas costs in their energy or capacity market offers, including review of offer caps, and to make changes to energy market offers during the operating day	Market Construct Process Change or Addition Technology	In progress – this is an active discussion in PJM and across the energy industry

[23] http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx

ID	Category	Recommendation	Type	Status
		3. Consider potential market rule changes that would allow generators to reflect fuel availability in their start-up and notification times 4. Improve the tools and processes for two-way communication with the gas industry to enhance situational awareness and better evaluate impact to PJM generation 5. Improve reporting of availability for units that are not committed day-ahead to include access to fuel and consider methods for validation		
4	Fuel Limited Resources	For those units with fuel limitations look to: 1. Improve tools that allow sharing of fuel-limited details with PJM including tracking dual-fuel capability and availability 2. Review operator communications with respect to fuel-limited generation commitment decisions for accuracy and consistency 3. Confirm mechanism by which resources' seek waivers for fuel emission limitations and better understand conditions under which relief may be granted	Technology Process Change or Addition	New
5	Fuel Specific Limitations	Examine difficulties experienced by generators during natural gas emergency procedures and consider: 1. Methods to call on long-lead generation based on fuel procurement limitations during extreme conditions 2. Changes to allow adjustment of start times based on changes in fuel utilized 3. Requirements for generation units whose primary fuel may not be natural gas but that require gas to operate	Market Construct Process Change or Addition	New
6	Energy Market Uplift	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate recommendations and PJM rule changes: 1. Review the cost allocation of energy market uplift charges 2. Investigate potential mechanism to allocate uplift during emergency operations when rates are extreme 3. Investigate methods and procedures for reducing the amount of uplift to be paid	Market Construct	In progress – Energy Market Uplift Senior Task Force
7	Interregional coordination	In order to increase situational awareness with the VACAR Reserve Sharing Group and VACAR Reliability Coordinator: 1. Define and review PJM emergency procedures and overall communications. Review operating agreements (including VACAR Reserve Sharing Group Agreement) 2. Include language regarding coordination of emergency procedures	Process Change or Addition Communication & Notification Protocols	New

ID	Category	Recommendation	Type	Status
8	Unit Commitment	Evaluate provisions in Manual 11 to determine where changes may be appropriate such as clarification and training regarding: 1. Start-up costs and cancelled dispatch provisions in Attachment C 2. Switching schedules	Process Change or Addition	New
9	Voltage Reduction Emergency Procedure	Review the voltage reduction capabilities of transmission owners to better understand current capabilities and determine if there are additional requirements that need to be developed: 1. Survey transmission owners to understand existing voltage reduction capabilities (amount, time frame, etc.) 2. Enhance Manual 13 with specifics on Voltage Reduction Warnings for TOs without SCADA control	Process Change or Addition	In Progress –this is being conducted and reviewed in the SOS-T and OC.
10	Emergency Energy Bids	Review and enhance the tools and processes for accepting Emergency Energy Bids	Technology Process Change or Addition	In progress
11	Regulation Market Rules	PJM stakeholders should consider reexamining the performance of the Regulation Market during January. Specifically: 1. Investigate whether the division by the performance score is appropriate 2. Investigate whether the minimum participation requirements are adequately high enough 3. Investigate the possibility of going short regulation during system peaks	Market Construct	New
12	External Capacity	Develop processes and tools that will: 1. Confirm that external capacity resources either bid into the day-ahead market or submitted eDart tickets that they are unavailable 2. Track the output of external capacity resources to ensure they are not submitting an outage into eDart and selling energy into a different market 1. Track the real-time output of external units cleared in the day-ahead market to confirm they are meeting obligations (tag validation versus commitment) 2. Develop ability to notify, track and confirm units that have not cleared in the day-ahead market but are recalled by PJM due to a capacity emergency such as Max Emergency	Process Change or Addition	New
13	Communications & Procedures	Review and improve how the Emergency Procedures tool is used to communicate, both internally and externally, and develop solutions to address the following topics: 1. Consider adjustments to the roles and responsibilities for communications during emergency procedures 2. Refine training to reinforce processes and tools	PJM & Member Dispatcher Training Communication & Notification Protocols	New

ID	Category	Recommendation	Type	Status
14	Public Appeals	In order to better implement and use public appeals for conservation, PJM should: 1. Evaluate and consider the impact of calls for conservation and investigate where or how to use the data 2. Improve process for public notification during emergency procedures (C1/C2) 3. Review triggers for public notifications and associated transmittal protocols 4. Review both the content and processes for public appeals in Manual 13	Technology	New

In addition to the above recommendations, which are focused largely on PJM practices, PJM's Executive Vice President of Operations and Planning Michael J. Kormos outlined in testimony before FERC as well as the U.S. Senate Energy and Natural Resources Committee the need for a broader look by policymakers on the relative transparency and flexibility of the natural gas markets. As noted above, some of the more onerous and inflexible terms and conditions, such as requiring commitments to take gas ratably throughout a three-day weekend in order to assure supplies on the first business day thereafter, were completely at odds with the more constrained day-ahead and real-time commitments in the wholesale electricity markets. Moreover, the lack of transparency and liquidity in gas markets made it extremely difficult to verify much of the information being provided and undoubtedly contributed to the price spikes and additions of onerous terms and conditions. These reforms are beyond PJM's ability to effectuate. They instead require a larger look from policymakers at the gas markets and their relative flexibility and transparency in the face of rising electric generation dependence on natural gas. PJM reiterates its request for a focused look on these issues by policymakers building on many of the experiences outlined in this report. PJM stands ready to assist in those efforts.

Appendices

Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals

The PJM Real-Time Market is a spot market in which instantaneous locational marginal prices are calculated every five minutes based on actual grid operating conditions. The table below shows the number of five-minute intervals each day that each resource type was marginal and set the LMP. On January 7 and January 24, generation was the marginal price-setting resource for most intervals, except for a few intervals in which demand response set prices. Emergency purchases did not set prices.

Figure 40: Number of Intervals Each Resource Type Set LMP

Day	Generator	Demand Response	Emergency Purchase
Jan. 7	225	63	0
Jan. 22	281	7	0

Appendix B: Locational Marginal Prices in Shortage

This table shows the intervals in which the real-time security constrained economic dispatch engine was in shortage conditions. There are 12 five-minute intervals every hour. For hour 19 (7 p.m.) on January 6, only the last five minutes of the hour were in shortage. For Hour 20 (8 p.m.) shortage conditions were from interval one to interval nine, which means in hour 20 shortage lasted for 45 minutes (nine five-minute intervals).

Figure 41: Intervals in Shortage Conditions

Day	Hour	First Interval	Last Interval
Jan. 6, 2014	19	12	12
	20	1	9
Jan. 7, 2014	7	5	12
	8	1	12
	9	1	12
	10	1	12
	11	1	12
	12	1	4
	17	12	12
	18	1	2

Appendix C: Natural Gas System Critical Notices

January 6, 2014

Columbia:

Restricting non-firm natural gas deliveries in Ohio delivery points on through Tuesday (1/7).

Dominion:

Maintaining their restriction on non-firm natural gas deliveries onto the Texas Eastern pipeline in western Pennsylvania.

Maintaining their restriction non-firm natural gas deliveries into two Local Distribution Companies (Peoples Natural gas Company and East Ohio Natural gas).

Texas Eastern:

Restricting non-firm natural gas deliveries off of Leidy line.

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Warned that an operational flow order could be issued, which would restrict the flow of non-firm natural gas.

Restricting non-firm natural gas deliveries from producers in Marcellus and Dominion/Rockies Express pipelines due to natural gas quality issues.

Transcontinental:

Issued a system-wide operational flow order beginning today. The OFO restricts shippers (including power plants) from taking any natural gas over and above their nominated quantities on an hourly basis.

January 7, 2014

ANR Pipeline (flows into Chicago):

Emergency maintenance will be partially restricting flows into Chicago by 15 percent

Released the previously set OFO, but maintained an advisory that generators rate takes off of pipeline.

Injections have been limited at Joliet and Woodstock, IL, which will lower pressures on the pipeline on points northward.

Columbia:

Restricting non-firm natural gas deliveries in Ohio delivery points on through Tuesday (1/7).

Restricting all non-firm natural gas deliveries at several delivery points throughout Ohio on Tuesday (1/7).

Restrictions on all non-firm natural gas deliveries into eastern Virginia on Tuesday (1/7).

Dominion:

Maintaining their restriction on non-firm natural gas deliveries onto the Texas Eastern pipeline (which flows into NYC) in western Pennsylvania.

Maintaining their restriction non-firm natural gas deliveries into two Local Distribution Companies (Peoples Natural gas Company and East Ohio Natural gas).

Requesting that all shippers maintain offtakes from the system at or below their nominations.

Texas Eastern:

Restricting non-firm natural gas deliveries off of Leidy line.

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Restricting non-firm natural gas deliveries into Philadelphia, Pa.

Warned that an operational flow order could be issued, which would restrict the flow of non-firm natural gas.

Restricting non-firm natural gas deliveries from producers in Marcellus and Dominion/Rockies Express pipelines due to natural gas quality issues.

Issued a notice on the morning of the 25th that a compressor east of Delmont, Pennsylvania. This reduced flows east of Delmont by 575,000 MMBtu, which is just east of Pittsburgh.

In the afternoon of 1/7, the Delmont Compressor Station is currently back online and operating at 70 percent capacity, which should help maintain/build pressure on the pipeline into eastern PJM.

Stated that No-Notice Service will be eliminated on 1/7 in response to compressor outage.

Issued operational flow orders on the Philadelphia and Section M-3 (which leads into Philadelphia), due to lower pressures caused by the Delmont Compressor outage.

Issued a critical notice that restricts takes off the pipeline after 4:30pm to their uniform hourly nominated quantity.

The Unionville Compressor station near Pittsburgh is out. Details are currently unavailable on the effect on operations, but it should affect natural gas delivery east of Pittsburgh.

Transcontinental:

Issued a system-wide operational flow order (OFO).

Natural gas deliveries out of the Marcellus are restricted at points due to high demand.

Stated that injections from producers have been lower than expected (the amount was not disclosed) and that nominations on the pipeline will be reduced based on priority (i.e.: non-firm will get cut first).

Suspending the nomination reductions caused by lower injections from producers.

January 21, 2014

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania today (1/21) through Thursday (1/23).

Dominion:

Warning that starting 6pm, January 16, and into the next week, that generators need to limit takes from the pipeline to equal of their hourly nominated quantities. If not, Dominion may issue an operational flow order to maintain pipeline reliability.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (January 20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order, effective starting today (1/21), which requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

January 22, 2014

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly, takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Advising generators to limit takes from the pipeline to equal of their hourly nominated quantities.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (1/20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

<u>January 23, 2014</u>

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly, takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Eliminating non-firm deliveries at several points in Pennsylvania and Ohio.

Advising generators to limit takes from the pipeline to equal of their hourly nominated quantities.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (1/20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

January 24, 2014

ANR:

Issued an “Extreme Condition” warning in Chicago, which will limit a consumer’s hourly takes from the pipeline.

Columbia:

Declared a “Critical Transport” advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Eliminating non-firm deliveries at several points in Pennsylvania and Ohio.

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Saturday (1/25), NGPA is limiting firm through some southern segments of its pipeline.

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline.

January 27, 2014

ANR:

Issued an “Extreme Condition” warning in Chicago.

Columbia:

Declared a “Critical Transport” advisory for northern Ohio and western Pennsylvania.

Restricting storage withdrawals of natural gas due to low inventories.

Dominion:

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that limits takes off the pipeline.

January 28, 2014

ANR:

Limiting pipeline withdrawals in Chicago.

Columbia:

Restricting non-firm transportation and storage withdrawals of natural gas due to low natural gas inventories, which can affect natural gas deliveries to generators, until Thursday (1/30).

Dominion:

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that limits takes off the pipeline.

Appendix D: Peak-Hour Period Availability Assessment

For each generation capacity resource having a capacity commitment (Reliability Pricing Model or Fixed Resource Requirement) for a given delivery year, PJM evaluates the resource's availability during the peak-period of that delivery year[24] relative to its expected availability, and a Capacity Market Seller is credited or charged to the extent the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short of the expected availability of such resources.

The peak-period equivalent forced outage rate (EFORp) is the measure of a generation resource's unavailability during the peak-period of the commitment delivery year. This rate is compared to the resource's expected unavailability rate as measured by the resource's five-year average equivalent forced outage rate (EFORd-5). For purposes of this assessment, the EFORp and EFORd-5 exclude outages deemed outside management control. In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter-peak shall be excluded if it can be demonstrated that such failure was due to non-availability of natural gas to supply the unit.

Generation unit availability for the commitment delivery year (Committed installed capacity * (1 – EFORp)) is compared to expected generation unit availability (Committed installed capacity * (1 – EFORd-5)) to determine the excess or shortfall in Peak-Hour Period availability for each generation capacity resource[25]. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller in each locational delivery area is the net of the shortfalls and excesses of all of the seller's resources in that locational delivery area.

A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller with a net shortfall in an locational delivery area, where such charge is equal to the shortfall quantity times the Seller's weighted average Resource Clearing Price for the locational delivery area.

Preliminary Peak-Hour Period Availability determinations have been made to determine the impact of high forced outage rates experienced in January 2014. The estimates are very preliminary and subject to change upon finalization of EFORp values for delivery year 2014 but the results do show higher EFORp values and higher Peak-Hour Period Availability charges for 2013/14 Delivery Year relative to two prior delivery years.

11/12 Daily Peak-Hour Period Availability Charges: $12,838.57

12/13 Daily Peak-Hour Period Availability Charges: $25,822.98

13/14 Preliminary Daily Peak-Hour Period Availability Charges: $45,585.71

13/14 Preliminary with January Daily Peak-Hour Period Availability Charges: $112,387.99

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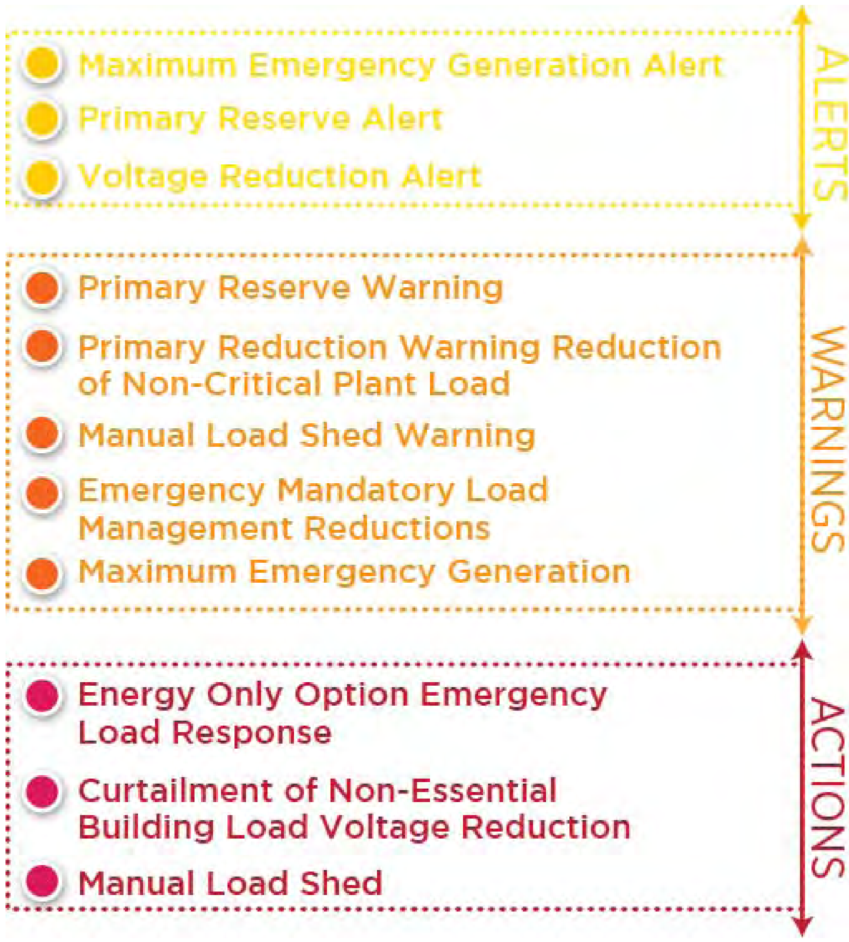
[24] For purposes of this assessment, the peak-period is defined as hours ending 3 p.m. through 7 p.m. for each non-holiday weekday during the calendar months of June through August and hours ending 8 a.m. through 9 a.m. and 7 p.m. through 8 p.m. for each non-holiday weekday in January and February. This peak-period definition encompasses approximately 500 hours in a delivery year.

[25] The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at either such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

Appendix E: Emergency Procedures in January



Wednesday, January 1

9:10 Cold Weather Alert issued for 12/30/13-01/03/14, ComEd Control Zone

9:10 Cold Weather Alert issued for 12/30/13-01/03/14, ComEd- Control Zone

Friday, January 3

6:25 TLR Level 1, PJM-RTM — Canceled: 1/4/2014 12:41

10:55 Cold Weather Alert issued for 1/6/14, PJM - RTO (Except MidAtl & Dom) — Canceled: 1/7/2014 4:10

11:00 Cold Weather Alert issued for 1/7/14, PJM- RTO — Canceled: 1/7/2014 22:56

Saturday, January 4

12:41 TLR Level 0 PJM RTO — Canceled:1/4/2014 17:57

Monday, January 6

11:25 EEA1 and Max Emergency Generation Alert PJM - RTO — Canceled: 1/7/2014 22:56

17:01 Spinning in PJM – RTO — Canceled: 1/6/2014 18:09

17:02	Shared Reserves Scheduled from NPCC – 775 MW PJM – RTO	Canceled: 1/6/2014 17:15
19:27	Voltage Reduction Warning PJM – RTO	Canceled: 1/6/2014 21:23
19:33	Max Emerg Gen - RTO	Canceled: 1/6/2014 21:03
19:50	Voltage Reduction Action of 5% PJM – RTO	Canceled: 1/6/2014 20:45
21:18	Shared Reserves Scheduled to NPCC – 163 MW PJM – RTO	Canceled: 1/6/2014 21:56
21:20	Spinning Reserves in MIDATL	Canceled: 1/6/2014 21:45
23:18	Spinning Reserves in RTO	Canceled: 1/6/2014 23:52
23:21	Shared Reserves Scheduled from NPCC – 800 MW	Canceled: 1/6/2014 23:24

Tuesday, January 7t

0:55	Reserve Reqt -2433MW, Estimated Reserve 1950 MW	Canceled: 1/7/2014 12:14
1:53	Energy Request for 06:00 through 11:00 hours EPT today	Canceled: 1/7/2014 12:12
2:51	Voltage Reduction Warning	Canceled: 1/7/2014 12:14
4:30	Max Emerg Gen	Canceled: 1/7/2014 12:14
4:30	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/7/2014 11:00
4:30	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/7/2014 11:00
6:27	Spinning in PJM for Max Gen	Canceled: 1/7/2014 6:38
6:27	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 7:30
8:14	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 8:25
8:20	Spinning in PJM for Unit Trip	Canceled: 1/7/2014 9:01
8:45	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 21:28
9:38	Cold Weather Alert for 1/8/2014	
11:00	Member to call Member Relations during cold weather operations	Canceled: 1/8/2014 10:35
12:00	EEA1 and Max Emergency Generation Alert	Canceled: 1/8/2014 18:35
13:30	Energy Request for 17:00 through 21:00 hours EPT	Canceled: 1/7/2014 18:16
15:00	Max Emerg Gen	Canceled: 1/7/2014 18:16
15:00	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/7/2014 18:16
15:00	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/7/2014 18:16
15:00	Max Emerg Gen Action Trans	Canceled: 1/7/2014 14:52

Wednesday, January 8

5:00	Max Emerg Gen	Canceled: 1/8/2014 8:00
5:00	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/8/2014 7:02
5:00	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/8/2014 7:02
5:30	Emergency Energy Request	Canceled: 1/8/2014 7:43
9:30	Cold Weather Alert for 01/08/2014	
12:00	EEA1 and Max Emergency Generation Alert	

Friday, January 10

11:46	Spinning in RFC for 2 Units Trip	Canceled: 1/10/2014 11:58

Tuesday, January 21

11:19	Cold Weather Alert for 01/21/2014, PJM - RTO (Except MidAtl & Dom)	
13:52	Spinning in RFC for Unit Trip	Canceled: 1/21/2014 13:58
21:26	Spinning in PJM for Unit Trip	Canceled: 1/21/2014 21:33
21:29	Shared Reserves: 800 MW with NYISO	Canceled: 1/21/2014 21:39

Wednesday, January 22

10:15	Special Notice-may call Max Emerg Gen	Canceled: 1/22/2014 21:01
11:19	Cold Weather Alert for 1/22/2014, PJM- RTO	
14:00	EEA2 and Emergency Load Management w/Short Lead Tm BGE /PEPCO	Canceled: 1/22/2014 21:00
14:00	EEA2 and Emergency Load Management w/Long Lead Tm BGE/PEPCO	Canceled: 1/22/2014 21:00
14:00	Max Emerg Gen BGE / PEPCO	Canceled: 1/22/2014 21:00
17:20	Max Emerg Gen BGE / PEPCO	Canceled: 1/22/2014 21:00
17:36	Shared Reserves: -117MW with NYISO PJM- RTO	Canceled: 1/22/2014 18:00
17:54	Spinning in MIDATL for Transfers	Canceled: 1/22/2014 18:02
19:30	EEA1 and Max Emergency Generation Alert AP/MidAtl/Dom	Canceled: 1/24/2014 0:14
20:03	Voltage Reduction Alert BGE/ PEPCO	Canceled: 1/24/2014 0:14
20:56	Shared Reserves:-73MW with NYISO	Canceled: 1/22/2014 21:06

Thursday, January 23

4:30	EEA2 and Emergency Load Management: Short AP /Mid-Atlantic /Dom	Canceled: 1/23/2014 4:58
4:30	EEA2 and Emergency Load Management: Mid-Atlantic	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long AP/Mid-Atlantic/Dominion	Canceled: 1/23/2014 4:58
4:30	EEA2 and Emergency Load Management: Short AP	Canceled: 1/23/2014 8:29

4:30	EEA2 and Emergency Load Management: Long Dominion	Canceled: 1/23/2014 8:29
4:30	Max Emerg Gen AP/Mid-Atlantic/Dominion	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long AP	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long Dominion	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long Mid-Atlantic	Canceled: 1/23/2014 8:29
4:50	Emergency Energy Request PJM – RTO	Canceled: 1/23/2014 8:05
12:00	Cold Weather Alert for RTO on 1/23/2014	
14:00	Max Emerg Gen Action Trans AP /Mid-Atlantic / Dominion	Canceled: 1/23/2014 19:00
14:00	EEA2 and Emergency Load Management: Short AP /Mid-Atlantic /Dominion	Canceled: 1/23/2014 19:00
14:00	EEA2 and Emergency Load Management: Long AP /Mid-Atlantic /Dominion	Canceled: 1/23/2014 19:00
19:15	EEA1 and Max Emergency Generation Alert Mid-Atlantic	Canceled: 1/25/2014 1:36

Friday, January 24

4:30	Max Emerg Gen AP /Mid-Atlantic/ Dominion	Canceled: 1/24/2014 8:45
4:30	EEA2 and Emergency Load Management: Short AP/Mid-Atlantic/Dominion	Canceled: 1/24/2014 8:45
4:30	EEA2 and Emergency Load Management: Long AP/Mid-Atlantic/Dominion	Canceled: 1/24/2014 8:45
7:20	Voltage Reduction Warning BGE ;PEPCO	Canceled: 1/24/2014 9:37
12:00	Cold Weather Alert for RTO on 1/24/2014	

Saturday, January 25

0:22	Spinning in MIDATL for Transmission West transfers Mid-Atlantic	Canceled: 1/25/2014 00:32
22:30	TRL Level 3a PJM - RTO	Canceled: 1/26/2014 5:28

Sunday, January 26

5:28	TRL Level 1 PJM - RTO	Canceled: 1/26/2014 8:23
8:23	TRL Level 0 PJM – RTO	Canceled: 1/26/2014 8:23
12:11	Spinning in PJM for Unit Trip PJM- RTO	Canceled: 1/26/2014 12:11

Monday, January 27

8:45	Voltage Reduction Alert PJM – RTO	Canceled: 1/28/2014 8:32
8:45	Primary Reserve Alert, PJM – RTO	Canceled: 1/28/2014 8:32
8:45	EEA1 and Max Emergency Generation Alert PJM – RTO	Canceled: 1/28/2014 8:32
16:24	C2 Statement for Cold Weather emergency	Canceled: 1/28/2014 21:02

Tuesday, January 28

10:00	Cold Weather Alert for 1/28/2014 for RTO	

Wednesday, January 29

8:45	Cold Weather Alert for 1/29/2014 for RTO	
17:45	TLR Level 3a, PJM – RTO	Canceled: 1/30/201414:15

Thursday, January 30

5:51	Max Emerg Gen, Mid-Atlantic/Southern	Canceled: 1/30/2014 9:06
6:50	Voltage Reduction Warning, PJM – RTO	Canceled: 1/30/2014 7:34
14:15	TLR Level 0, PJM – RTO	Canceled: 1/30/2014 14:15
17:49	Shared Reserve: -83MW w/ NYISO	Canceled: 1/30/2014 18:05

Friday, January 31

10:05	Spinning in MIDATL for Unit Trip Mid-Atlantic	Canceled: 1/31/2014 10:17