PJM Cold Snap Performance
Dec. 28, 2017 to Jan. 7, 2018

PJM Interconnection
Feb. 26, 2018

Note:

On February 27, 2018, this paper was updated to correct minor clerical errors.

On March 3, 2018, Figure 22 was updated to correct the colors of the trend lines.

On April 13, 2018, the paper was updated to add a footnote on page 11.

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Executive Summary

At PJM Interconnection, the reliability of the bulk power system is our most important responsibility. We are committed to using all of the market, operational and planning tools at our disposal to ensure that the grid remains reliable. PJM has prepared this report to document the performance of the bulk power system during the recent cold snap. With excellent coordination and cooperation with our members, our analysis shows that the grid in the PJM footprint is diverse and strong and remains reliable.

The cold snap ran from Dec. 28, 2017, to Jan. 7, 2018, during which PJM experienced one of our top 10 winter peak demand days of all time. The peak occurred on Jan. 5, 2018, hour ending (HE) 19 with a peak of 137,522 MW.
As detailed in the report, neither the temperatures nor customer demand reached the levels experienced in 2014 during the Polar Vortex. During the recent cold snap, PJM did not call a performance assessment interval, a 72-hour maintenance recall or any transient shortage intervals. However, the system was well tested and, as detailed in this report, there were indicators of improved performance of generating resources since 2014. Overall, the grid and the generation fleet performed well. Even during peak demand, PJM had excess reserves and capacity.[1]

Data as of Feb. 2, 2018

The generation outage information in this report is based on real-time operational data, which represents the best information available to PJM as of Feb. 2, 2018. Final causes and durations of outages are recorded in the Generator Availability Data System (GADS) data, which is submitted to PJM by the generation owners 20 days following the last day of the month in which the outage occurred.

How PJM Has Progressed: The Polar Vortex vs. the Cold Snap

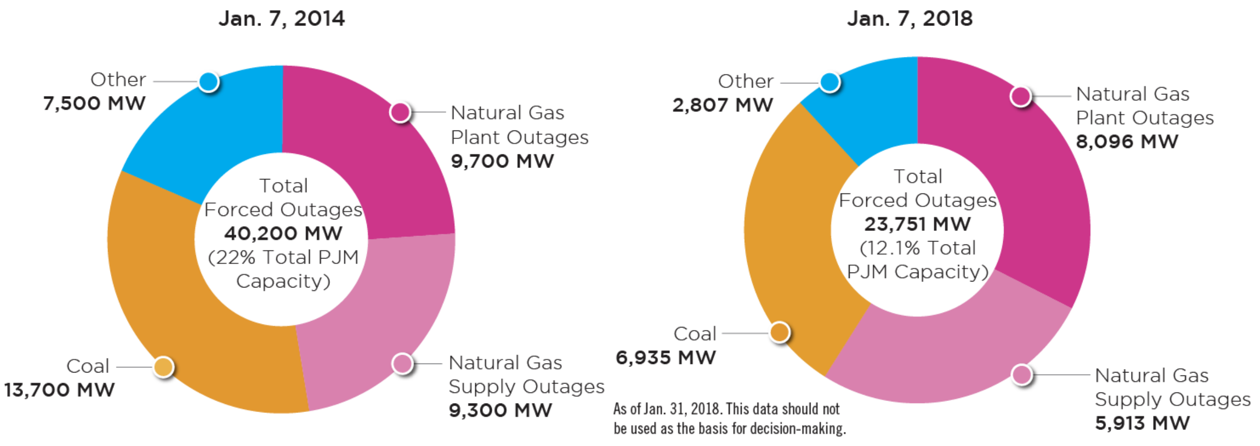
In most respects, the recent cold snap was milder than the 2014 Polar Vortex – the temperatures were not as low, the wind chill was less severe, and the demand for electricity was lower, in part due to the cold snap occurring during a holiday week. However, the cold snap did last longer, which led to some degrading of generator performance over time.

In contrast, the Polar Vortex was characterized by multiple days of below-zero temperatures through much of the PJM footprint. Though even at the height of the Polar Vortex, PJM did not face imminent blackouts, the performance of the generation fleet at that time was not where it needed to be to meet system conditions. There were a significant number of plant outages from generation of all types. There was a significant reduction in forced outages between the recent cold snap and the 2014 Polar Vortex. This is illustrated in Figure 1, which compares the hour with the highest forced outages experienced during the Polar Vortex to the hour with the highest forced outages experienced during the recent cold snap. (Note: the historical average winter forced outage rate prior to the Polar Vortex was approximately 7 percent).

[1] As indicated in the January 23, 2018, testimony of PJM CEO Andrew Ott before the US Senate Energy and Natural Resources Committee, this data does not indicate complacency about the state of the grid going forward. Specific reforms associated with enhancing the resilience of the grid were outlined in Mr. Ott's testimony and will be addressed in further detail in PJM's Comments to the Federal Energy Regulatory Commission.

It should be noted that under stressed conditions, units of all types would face forced outages. The complexity of machinery, stressed ambient conditions and elongated periods of operation all can drive units to trip for any number of reasons. As a result, although PJM's Capacity Performance tariff changes and related changes were all designed to incent improved system performance, a certain degree of forced outages will always be present. In this case, despite stressed conditions and the situation not being 100 percent comparable to the Polar Vortex, forced outages, both at the plant level and in the area of gas supply, were all significantly reduced.

Figure 1. 2014 and 2018 Forced Outages by Fuel Type



Many factors drove this improved performance. In addition to the milder weather, these include enhancements PJM and its member companies have put in place in the years since the Polar Vortex, such as increased investment in existing resources, improved performance incentives, enhanced winterization measures and increased gas-electric coordination.

Capacity Performance

Capacity Performance was designed to ensure that generators are available when required. PJM has seen significant new entry (nearly 40,000 MW) of a diverse mix of fuel types since the inception of the capacity market. PJM has experienced over 20,000 MW of coal retirements in the same period, and the average age of the coal units that have retired was over 50 years. In short, the markets have helped to incent new efficient generation of all fuel types and helped to retain existing generation needed to serve electric needs of customers in the PJM footprint.

Overall, there was a significant reduction of forced/unplanned outages when comparing the winter of 2014 to the recent cold snap. The reduction in forced outages is partially due to the lower impact of wind chill during the cold snap compared to the 2014 cold weather events.

Uplift

One telling data point from the experience of the cold snap was the significant increase in uplift charges. Over the last several years, uplift charges have been relatively low in PJM, averaging approximately $389,000 per day. By contrast, during the peak days of the cold snap, uplift charges averaged approximately $4.3 million per day. Uplift is paid when locational marginal prices do not reflect the costs of operating units needed to serve load. During the cold snap, this condition occurred more frequently than it has in several years, indicating that on these days when the system is under additional stress, the actions the operators take to ensure that reliability is maintained are often not reflected in the transparent clearing prices. This problem, clearly evidenced by the cold weather experience, highlights the need for PJM and its stakeholders to evaluate reforms to address this issue in a timely manner. These reforms include enhancing the manner in which reserves are procured and priced so that all operator actions are included in price signals and enhancements to the calculation of locational marginal pricing. (See the Generator Uplift and Conclusion and Next Steps sections for more detail.)

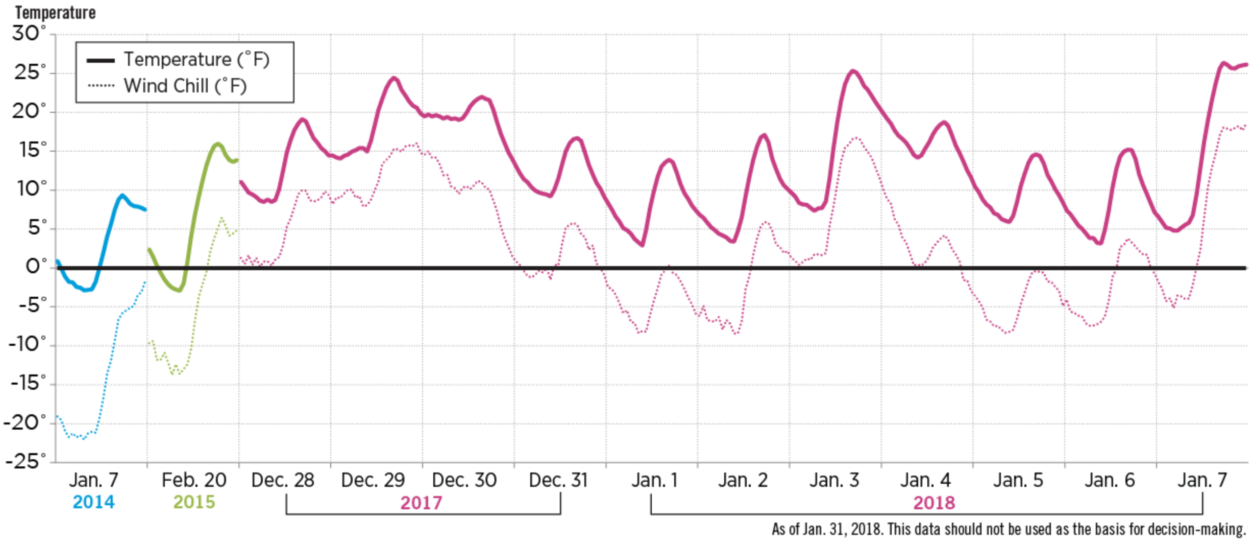
This report will explore the data from the recent cold snap and offer further insights and potential next steps for PJM and its stakeholders in fuel security, uplift and pricing strategy, and operating in stressed conditions.

Weather Conditions and Load Forecast

Though not yet over, the winter of 2017–2018 is already proving to be a cold one for PJM and its members. While individual cities in PJM's footprint set low temperature records for days between Dec. 27 (Chicago, Ill.) and Jan. 8 (Norfolk, Va.), the average temperature did not reach the extreme low limits that were experienced during our coldest days of 2014 and 2015. On the two days with the coldest average temperature, Jan. 7, 2014, and Feb. 20, 2015, the minimum temperature dipped below 0 degrees Fahrenheit. During the recent cold snap, the average temperature was coldest on the morning of Jan. 1, 2018, dropping to 2.9 degrees.

Figure 2 shows how the difference in wind chill between the Polar Vortex and this year's cold snap was even greater. The morning of Jan. 7, 2014, was by far the coldest, with the average wind chill across the PJM footprint dropping below -20 degrees, as compared to the lowest wind chill during the recent cold snap, which was -8.4 degrees.

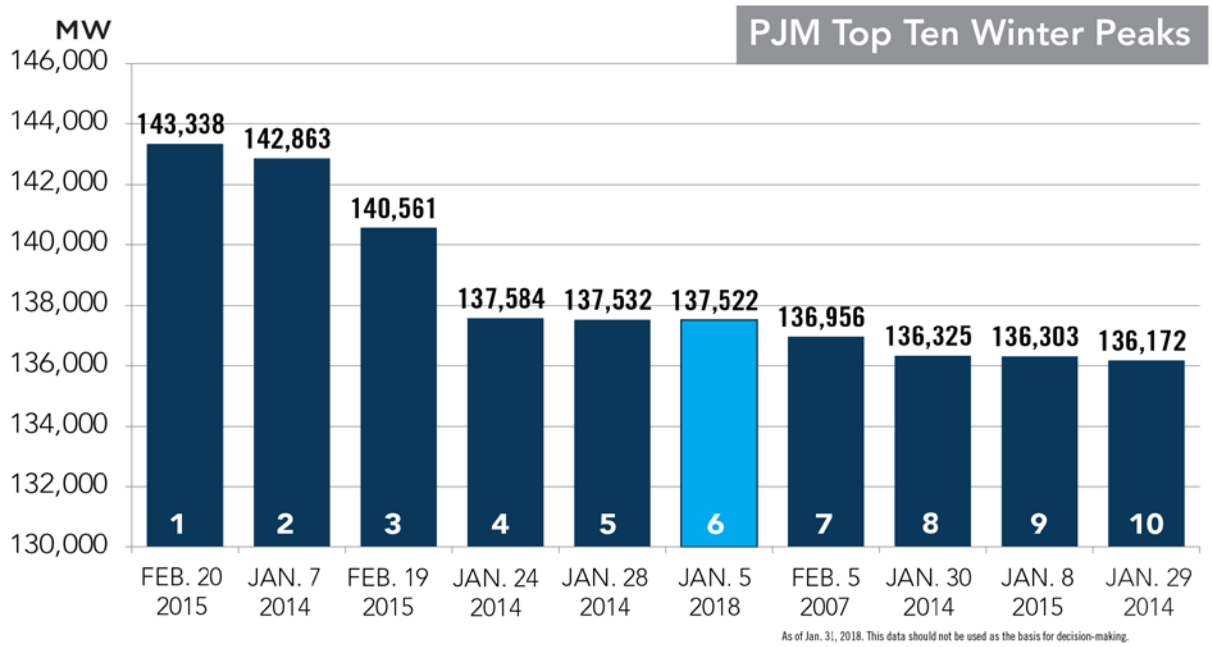
Figure 2. PJM Average Temperature and Wind Chill (Hourly)



While no individual hour of the 2017–2018 winter so far compares to the severity experienced during previous cold weather events, the duration of the cold has helped contribute to high demand conditions. The integrated hourly load value showed only one peak in the PJM top 10 winter peaks, which occurred on Jan. 5, 2018, HE 19 with a peak of 137,522 MW (see

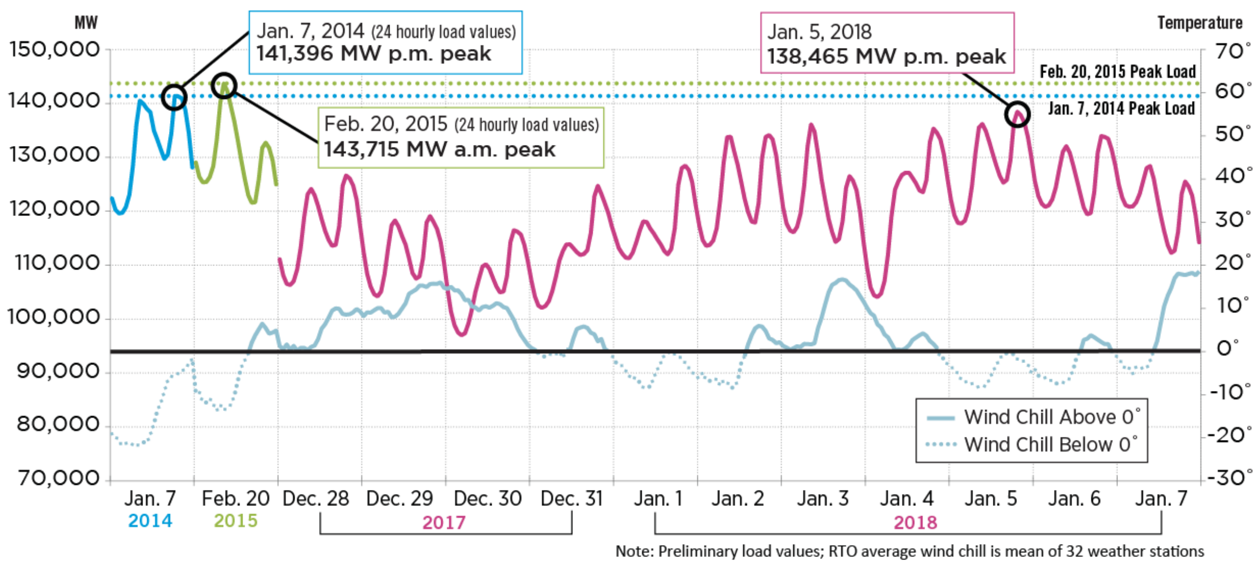
Figure 3). This peak occurred during the day with the lowest wind chill. While Jan. 1, 2018, was also quite cold, the effect of the holiday mitigated the impact on the load.

Figure 3. PJM Top 10 Winter Peaks



As indicated above, when you take into account the wind, the difference in apparent temperatures between the Polar Vortex and the cold snap becomes even greater. The morning of Jan. 7, 2014, was by far the coldest, with average wind chills across the PJM footprint dropping below -20 degrees. Figure 4 shows the comparison of average wind chill impact on RTO load.

Figure 4. RTO Load and Average Wind Chill



Load forecasting and the accuracy of the forecast are critical to PJM operations. The forecasted load is the basis for generation scheduling decisions and outage coordination. Any error, high or low, can significantly affect both reliability and prices. PJM's goal is to forecast load with an error rate of less than 3 percent.

The average error of the day-ahead load forecast during the cold snap was 2.20 percent. Many individual hours and days were well forecasted, including Jan. 2 when, in the middle of the prolonged cold weather, many people returned to work and school after an extended holiday weekend. This period was also punctuated by periods of higher load forecast error associated with some of the trickiest forecasting conditions – holidays, extreme temperatures and impactful weather events (in this case a snow storm on Jan. 4).

Operations

Winter Preparations

Operational preparations for winter in PJM begin months before winter actually begins. The 2017–2018 year was no exception. To help ensure there were no operational concerns and all prudent steps had been taken to minimize any unplanned generation outage, the following actions were taken:

- **Annual Winter Emergency Procedure Refresher Training.** PJM requires all of its system operators to complete winter emergency refresher training each year. The training is posted on PJM's website and is available for all member operators to take.

- **Annual Winter Emergency Procedures Drill.** The annual Winter Emergency Procedures Drill was held on Nov. 7, 2017. During the drill, the emergency procedures documented in Manual 13: Emergency Procedures were simulated and communicated to system operators and other stakeholder participants to help them maintain familiarity with the execution of these procedures.

- **Operational Assessment Task Force (OATF) Study.** PJM completed this seasonal analysis, which included a winter peak demand analysis, as well as gas infrastructure failure contingencies encompassing each pipeline and local distribution company (LDC). The results indicated that no problems were anticipated.

- **Annual Implementation of Cold Weather Preparation Guideline and Checklist, Manual 14D, Attachment N.** This checklist was developed by PJM based on Polar Vortex and NERC lessons learned documented in their report "Winter Preparation for Severe Cold Weather Events."[2] This checklist is implemented by the generator owners and helps ensure they have taken the necessary steps to prepare their units for extreme cold temperatures, which reduces unplanned failures.

- **Generation Resource Operational Exercise, PJM Manual 14D, Section 7.5.1.** PJM schedules and tests generation that has not been online for the eight-week period preceding the winter (for non-Capacity Performance (CP) resources only). Similar to the checklist, this exercise helps minimize unplanned generator outages.

[2] http://www.nerc.com/pa/rrm/Documents/Winter_Preparation_for_Severe_Cold_Weather_Events_Webinar_20150903.pdf

Emergency Procedures

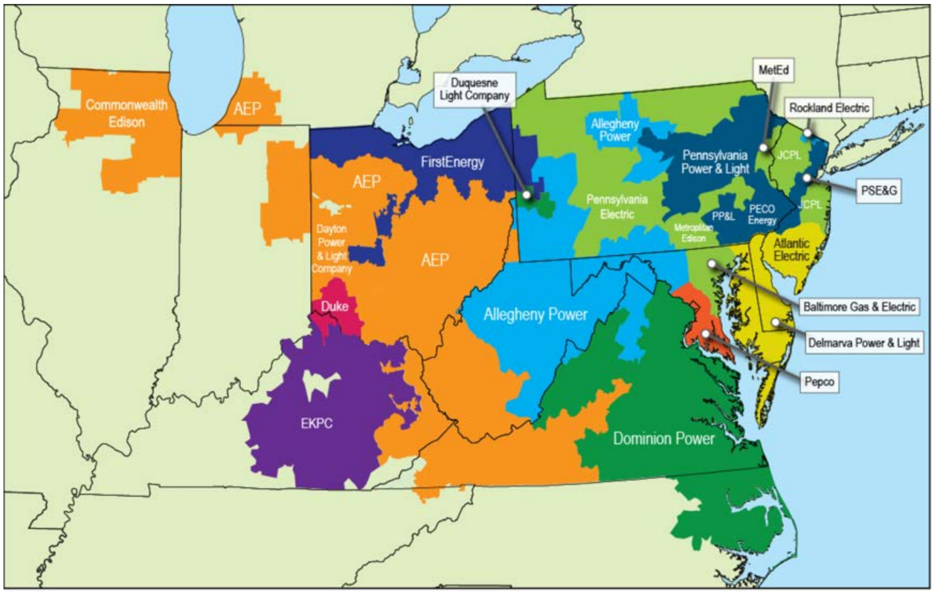
Cold Weather Alerts

Cold weather alerts are issued when forecasts indicate temperatures below 10 degrees Fahrenheit. The alerts serve to notify members of higher-than-normal demand and ask them to restore all available transmission and generation equipment and to defer any maintenance activities planned during the alert period.

As the near-term weather forecasts for Dec. 26, 2017, and beyond indicated extreme and extended cold weather, PJM began taking actions to raise awareness of these conditions and to position the system to maximize reliability.

On Dec. 25, 2017, PJM issued a cold weather alert for the ComEd region (see Figure 5 for a map of PJM service territory), effective Dec. 26, 2017, and extended the alert to the entire Western region of the PJM footprint, effective Dec. 27. In addition, PJM worked closely with Dominion transmission operators to schedule additional crews to restore a 500 kV line from Carson-Rawlings that was limiting interchange with the Virginia-Carolinas (VACAR) entities and bottling PJM generation. This line was scheduled out of service for maintenance and was restored to service the evening of Dec. 30.

Figure 5. PJM Service Territory



On Dec. 27, 2017, as weather forecasts indicated continued cold weather over a wider area of the PJM footprint, PJM issued additional cold weather alerts for the Western region, effective Dec. 30 and 31, and an alert for the entire PJM footprint, effective Jan. 1 and 2, 2018. These alerts were intentionally issued prior to the holiday weekend to ensure all members were aware and had the opportunity to coordinate with PJM on preparation activities.

On the morning of Friday, Dec. 29, PJM held a conference call with the System Operations Subcommittee –Transmission (SOS-T) members to review system projections through the weekend and into the following week to raise awareness and align operating plans.

As cold weather continued over the subsequent week, PJM issued additional cold weather alerts and held additional SOS-T conference calls. PJM also participated on daily conference calls with each neighboring ISO/RTO to maximize situational awareness of external conditions and provide updates on the emergency assistance PJM was able to provide, if needed.

Heavy Load Voltage Schedule Warnings and Actions

In addition to cold weather alerts, PJM issued heavy load voltage schedule warnings and actions on Jan. 4 and 5, 2018. These warnings and actions alert transmission owners to energize all capacitors, remove all reactors and optimize voltage schedules to help maximize the power transfer capability of the system. By taking these steps, PJM ensures the system is positioned in the most resilient manner possible, allowing us to move power from one area to another if there are major generator or transmission failures. These procedures are issued proactively and do not signify any capacity or transmission concerns.

Daily Gas Pipeline Analysis

During the cold snap, PJM implemented a new gas infrastructure analysis, codified in Manual 13, Section 3.8: Assessing Gas Infrastructure Contingency Impacts on the Electric System. This analysis projects transmission and reserve impacts of pipeline contingencies on the PJM system. The analysis did not indicate any transmission loading or generation reserve concerns so no additional operator actions were taken.

Outreach and communication were also crucial to helping PJM form accurate and reliable operating plans and execute those plans, which helped maintain the reliability of the system. Under FERC Order 787 and the existing Memorandum of Understanding with nine interstate pipelines, the PJM Gas-Electric Coordination Team was in communication with interstate pipelines in the PJM footprint on a daily basis to review operational conditions and potential generation impacts. Similar outreach was conducted with local distribution companies across PJM that serve gas generation facilities to coordinate potential unit interruptions. (PJM currently has data-sharing agreements in place with several larger LDCs in order to better share operational information to improve operational awareness and reliability.) This action ensured PJM was aware of any constraints that may have restricted the availability of gas to PJM generators. The team also confirmed constraints and impacts with generator owners in the PJM footprint and validated that any affected unit's availability and operating parameters were reflected in the PJM systems and complied with all PJM market rules.

Dispatch and Transmission Operations

Over the course of the cold snap, PJM and its members demonstrated strong coordination and reliable operations. There were very few transmission concerns.

System Conditions

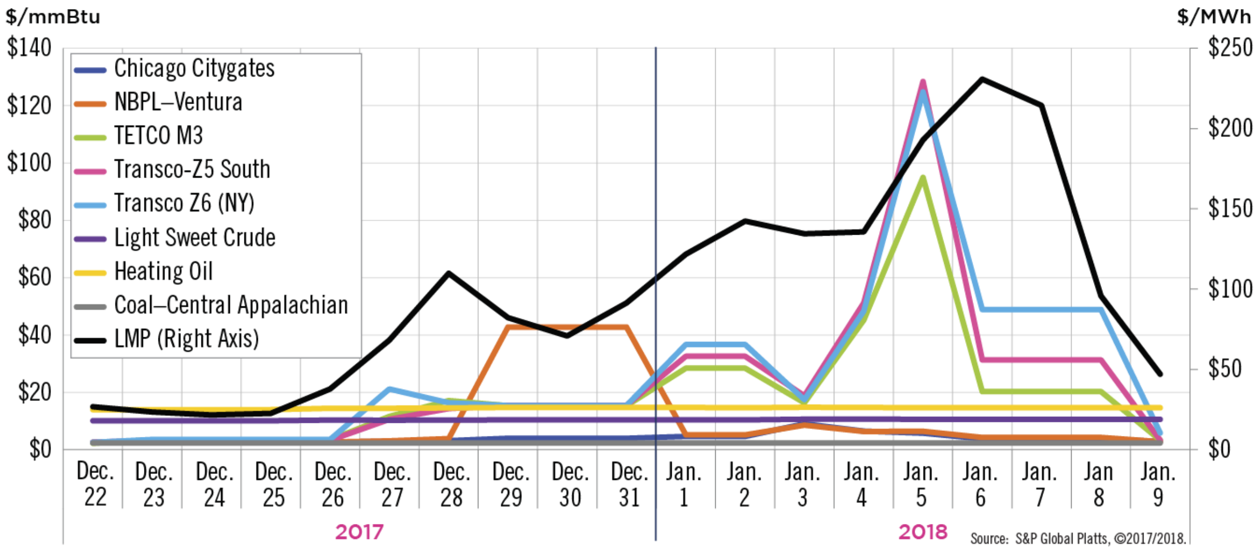
As discussed earlier in this paper, preliminary data shows that PJM observed one of its top 10 winter peaks during this cold snap, with the highest demand observed on Jan. 5, 2018 (HE 19, 137,522 MW). During periods of high demand, the grid performed well.

Congestion

In operating to meet demand, PJM uses the lowest-cost energy first, until a transmission constraint requires the dispatch of higher-cost generation. Congestion occurs when the lowest-cost energy is prevented from flowing freely to a specific area on the grid because heavy electricity use is causing parts of the grid to operate near their limits. PJM did observe congestion on several transmission facilities over the course of the cold weather, which is normal and indicated that generation re-dispatch was required to maintain system flows within thermal and reactive limits.

Several of the congested facilities seen in the cold snap had not experienced congestion since Feb. 2015, which was the last time cold weather had a significant impact on the system. For example, PJM experienced congestion on both the 5004/5005 and AEP-Dominion interfaces. Congestion on these facilities is indicative of high west-to-east and west-to-south power flows, respectively. The high power flows were caused by high system demand and price differences between eastern-southern generation and western area generation. The cost shift occurred as a result of natural gas pricing between these two areas of the PJM footprint, as can be seen in Figure 6. (See the Gas-Electric Coordination section for more detail).

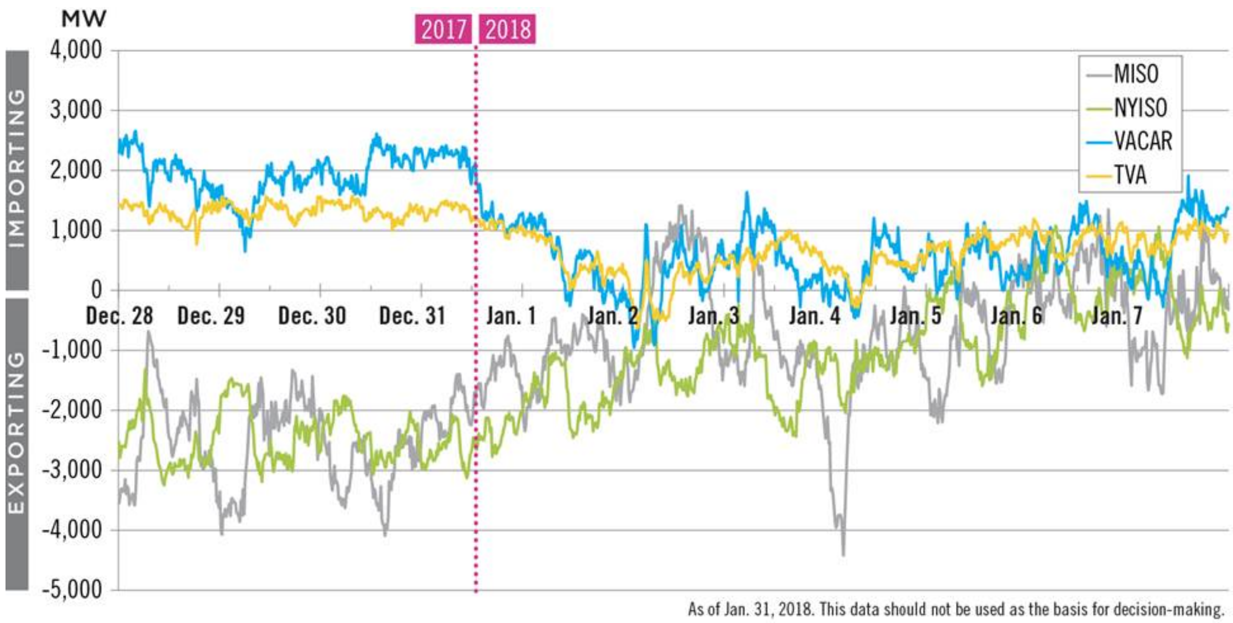
Figure 6. Average Daily Commodity Prices



Interchange

Figure 7 shows interchange with four major control areas through the cold weather period. See Figure 8 for the PJM interregional map, which shows the corresponding geographical location.

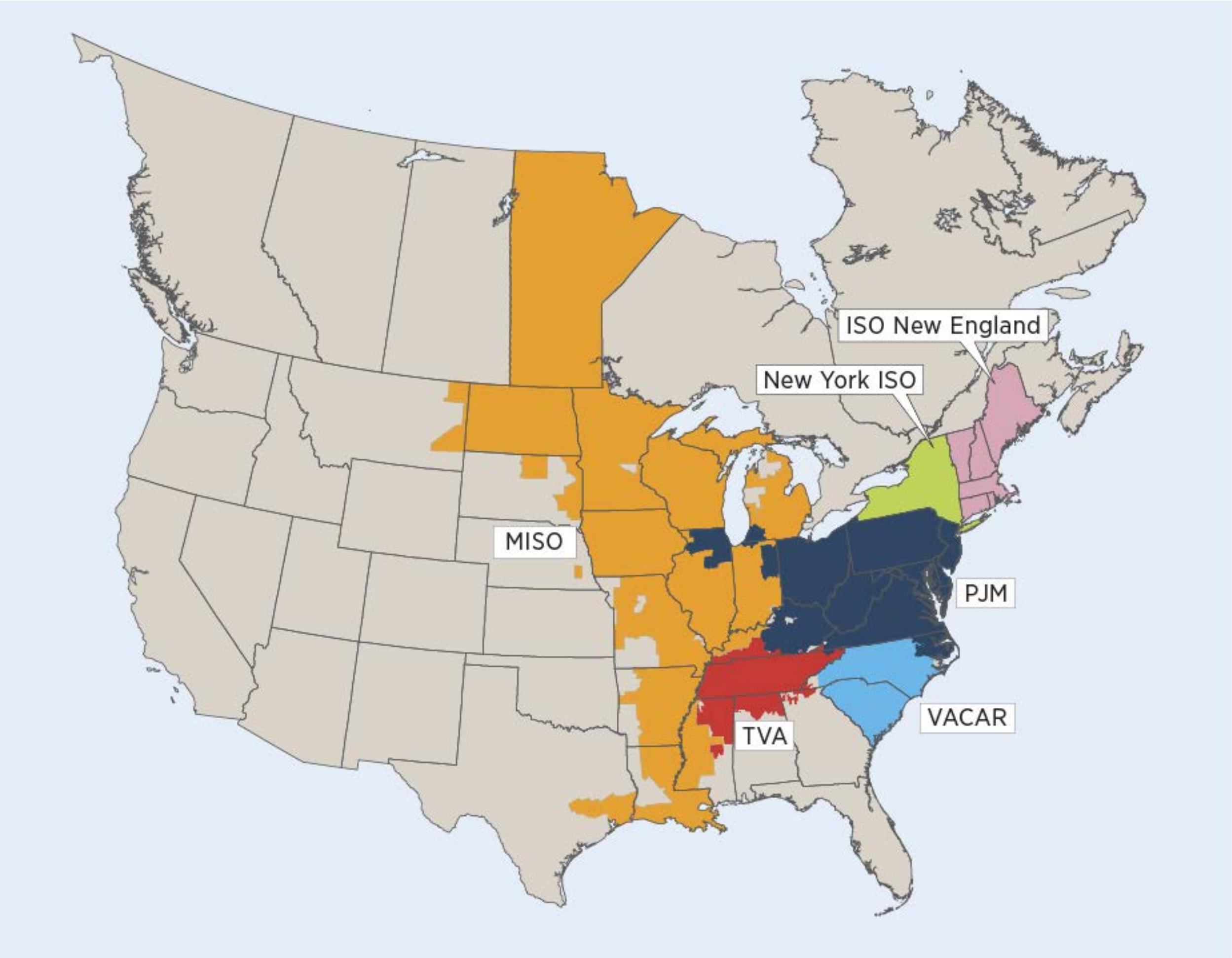
Figure 7. PJM Interchange, Dec. 28, 2017—Jan. 7, 2018



At the start of the cold snap, on Dec. 28 and Dec. 31, PJM interchange remained typical for the time of year. PJM was importing from the TVA and VACAR regions in the south and exporting to MISO and NYISO. On Jan. 1, 2018, the transactions started to flow more to the south. During this time, PJM's southern neighbors experienced some of their coldest conditions and needed assistance in meeting load and reserve requirements. This trend in interchange ultimately peaked on Jan. 2, 2018, when PJM interchange exported to the south. In a corresponding trend, PJM exports to MISO and NYISO decreased. Over the next several days, flows started to normalize again although the southern imports did not reach the same levels seen before the start of the cold weather. When PJM hit the peak for the week on the evening of Jan. 5, PJM imported from TVA, VACAR and NYISO.

The decreased exports and eventual imports with MISO and NYISO can ultimately be credited to economics. PJM prices were elevated, and both MISO and NYISO, not in emergency conditions, found it more economical to run more internal generation instead of scheduling the more expensive generation from PJM.

Figure 8. Interregional Coordination Map



Interregional Operations

PJM experienced seasonably cold weather with high, but not all-time high, demand levels during the week of Dec. 26–29, 2017. PJM operations were relatively normal, with normal interchange levels with our neighbors.

During that week, there was an outage of the Carson-Heritage 500 kV line, which is along the southern Dominion border. With this line out, there was heavy congestion with the Duke Progress border, which was controlled through re-dispatch and transmission loading relief (TLR). Given the forecast of higher system loads for the following week, Dominion brought crews in over the holiday weekend and the line was restored as Carson-Rogers Road-Heritage 500 kV on Dec. 30, 2017.

On Jan. 2, 2018, PJM was able to maintain more than adequate generation and reserves. However, PJM was not receiving the usual imports from the south. Instead, PJM was exporting to these neighboring balancing areas (see the Interchange section). A few of PJM's southern neighbors were in emergency energy conditions.[3]

[3] http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf

This resulted in many level 1 Energy Emergency Alerts (EEA-1s)[4] and an EEA-2 for Duke Energy Progress. PJM was able to support Duke Energy Progress with 400 MW of shared reserves to help maintain system reliability. The most severe congestion was observed on the Broadford #1 transformer for the loss of Broadford-Sullivan 500 kV, which was caused by heavy flows into TVA, combined with the ongoing TVA outage of Nagel (AEP)-Phipps Bend (TVA) 500 kV. For the Jan. 2 evening peak, VACAR and TVA were able to start additional generation and did not need further assistance.

On Jan. 3, temperatures remained much lower than originally forecast, which resulted in higher loads for both PJM and our neighbors. However, VACAR and TVA did not require imports as generator performance was improved over the previous operating day. Throughout the week, interchange levels returned closer to seasonal averages, which allowed PJM to import less expensive generation to help meet the demands of the Jan. 5 peaks.

While coordination calls were continually held with MISO and NYISO to discuss system status and reliability, no emergency procedures were declared by these neighboring areas.

Loads

Neighboring entities were experiencing elevated but seasonal system loads through Jan. 1. On Jan. 2, the severe cold weather increased loads significantly above day-ahead forecasts, particularly for the VACAR and TVA regions. VACAR and TVA reported peak loads of 45,542 MW and 43,575 MW, respectively. As previously noted, this led to increased imports from PJM to maintain system reliability. This proved to be the peak load for TVA during this cold snap as they experienced warmer weather moving forward. However, VACAR remained at similar load levels through this time and reached a reported peak of 45,957 MW on Jan. 5, 2018.

MISO and NYISO experienced similarly cold weather but did not approach record load demands. During this same cold snap, MISO and NYISO reported peak loads of 112,959 MW and 25,081 MW, respectively.

Emergency Procedures

The cold weather was not isolated to the PJM footprint and extended well past PJM's southern border down through the eastern region of the country. (See Figure 9 for NERC regions.) As a result, most external reliability coordinators declared a form of cold weather alert or conservative operations during the cold stretch from Jan. 1 through Jan. 17. On Jan. 1, Florida Reliability Coordinating Council (FRCC) declared an EEA-3 for less than two hours for a portion of their footprint. On Jan. 2, Southern Company, TVA, Santee Cooper, SCEG, FRCC and Duke Carolina all declared an EEA-1 and Duke Progress declared an EEA-2. These alerts ended on the same day they were issued. However, Santee Cooper entered an EEA-1 each day from Jan. 4 through Jan. 6.

On Jan. 7, widespread cold across the south once again increased the amount of emergency procedures. Duke Energy Carolina entered an EEA-1 and both Duke Energy Progress and Santee Cooper entered an EEA-2. Duke Energy Progress also declared an EEA-1 on Jan. 8.

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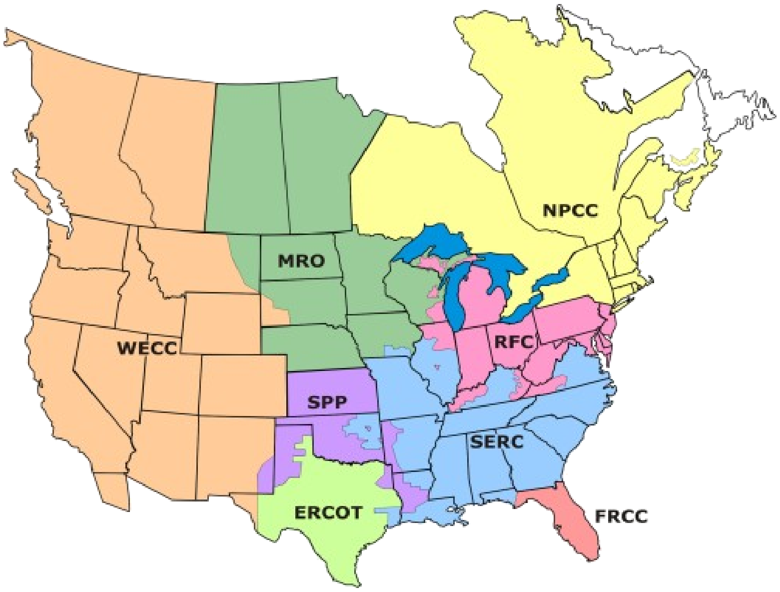
[4] Information on all EEAs included in this report was taken from NERC Testimony before the US Senate on January 23, 2018: https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=D982B4F9-ECAF-403B-88BA-C82D2634E2DA.

Figure 9. NERC Regions



Generation Performance

Overall, there was a significant reduction of forced/unplanned outages when comparing the winter of 2014 to 2015 and the recent cold snap. The reduction in forced outages is partially due to wind chill impact being lower during the cold snap than it was in 2014 and 2015.

To better understand the impact of Capacity Performance improvement efforts, PJM reviewed online generation and outage amounts and causes, including assessing performance for Capacity Performance and non-Capacity Performance resources.

However, before going further, it is important to explain the nature of the data at the time of the writing of this report.

GADS vs. eDart Data

The PJM eDART system is an online portal that is used in real-time operations to track generating unit capabilities on a minute-by-minute basis. PJM Generation Owners (GO) submit unit forced/unplanned outages and reductions through this portal during the current operating period so that, at any given time, PJM dispatch can assess unit availability and maintain adequate reserves to ensure system reliability.

When a GO submits an unplanned reduction or outage, the actual cause of a reduction, trip or start failure may not be known until much later and indeed may be different from the cause reported on the eDART ticket. This is partly due to the plant needing to focus on real-time operations at the initial trip with the expectation of a more detailed trip analysis when time permits. This is reconciled at the earliest by the 20th of the month following the month in which the outage occurred, using the Generator Availability Data System (GADS).

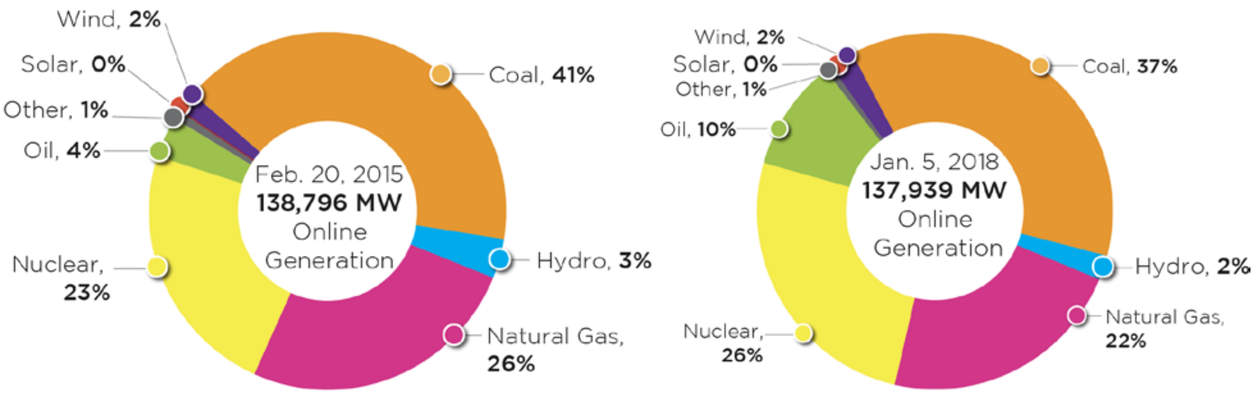
The eDART outage data, by design, is based on a snapshot in time, and not integrated over an hour. The GADS data, on the other hand, will be integrated over the hour. For example, if a unit had a full outage in the first half of an hour but became fully available in the second half of the hour, depending on the timing of the eDART data snapshot, it may appear as a 0 percent reduction or a 100 percent reduction, but not 50 percent — as would be recorded in GADS.

For these reasons, it is important to emphasize that the generation outage data provided and any associated analysis is subject to reconciliation with GADS data and is not final. PJM recommends that any decision-making or final conclusions based on the winter data wait until the final GADS data is released.

Generation Online

The amount of generation online at the 2018 peak hour was similar to the amount of generation online at the 2015 all-time winter peak (138,796 MW in 2015, compared to 137,939 MW in 2018). The generation fuel mix for at the 2018 peak load hour was similar to the 2015 all-time peak load generation online (see Figure 10).

Figure 10. 2015 vs. 2018 Online Fuel Mix (Peak)

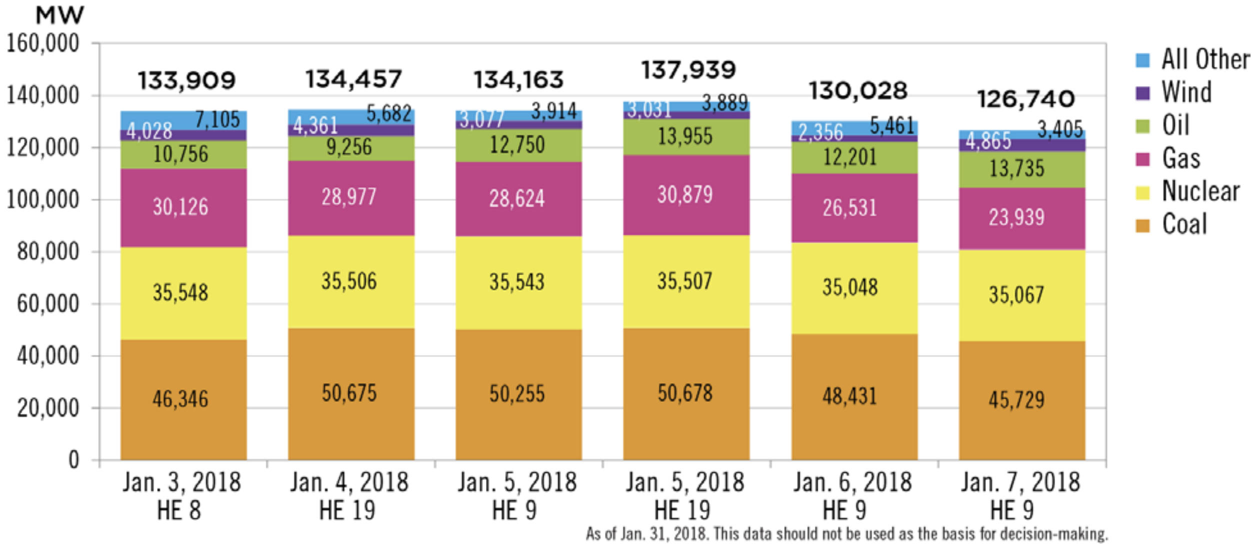


As of Jan. 31, 2018. This data should not be used as the basis for decision-making.

Figure 11 shows the trend of online generation throughout the cold snap. Online coal generation output was consistent through most of this period, but started to drop off later in the week, and online nuclear generation stayed at a consistent level throughout the week. Gas generation stayed online at a consistent level until later in the week, as increased interstate pipeline and local distribution company restrictions resulted in an increase in outages, primarily affecting those generators holding non-firm transportation contracts. However, generators holding firm transportation contracts can also be impacted by ratable take requirements. This can be manifested by generators needing to procure additional supply beyond what is needed to meet their day ahead award or dispatch commitment, which could result in reduced offer flexibility and needing to take a forced outage. Online oil generation steadily increased through later in the week due to a combination of economics as in some locations oil became cheaper than gas, together with a decreased availability of gas or coal units. At the 2018 peak hour, the online oil generation was at 10 percent (about 14,000 MW) of the total online generation. Of this 10 percent, about 32 percent of this comprised oil-only units, and 68 percent were dual-fuel oil units with gas as their primary fuel.

In comparison to the 2015 all-time winter peak fuel mix, during the 2018 cold snap, coal was a slightly lower percentage of online generation, oil was slightly higher and natural gas was lower. Much of the difference was based on economic decisions. PJM did not direct any generators to switch to operating on oil during the 2018 cold weather period. Many natural gas generators decided to switch to oil due to record-high natural gas spot prices in the Mid-Atlantic and Northeast, along with increased operational flow orders and ratable take requirements imposed by the interstate pipelines and local distribution company interruptions. Based on preliminary PJM outreach to generation representatives, the majority of reasons cited for the switch from gas to oil during the 2018 peak were a combination of interruptible gas curtailments by pipelines/LDCs or supply unavailability, with the balance attributable to a pure economic decision due to the significantly higher spot prices of natural gas.

Figure 11. Online Generation, Jan. 3–Jan. 7, 2018



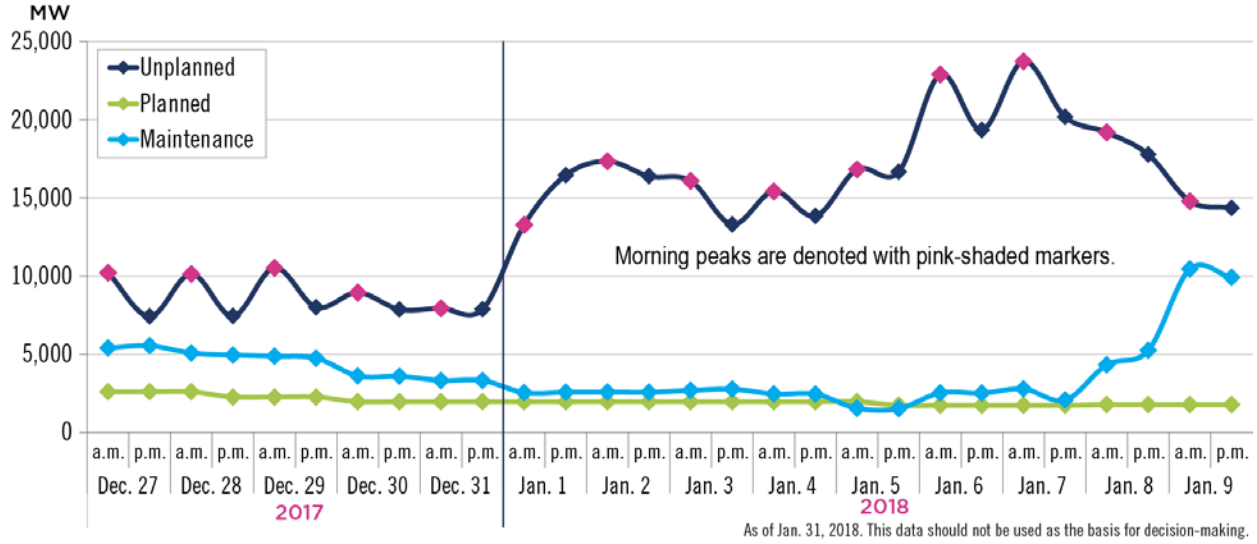
Generator Outages

As mentioned above, overall there was a large reduction in forced/unplanned outages between the 2014 Polar Vortex and the cold snap. Generator outages fall into three categories: planned, maintenance and unplanned. Unplanned generator outages, also known as forced outages, can challenge grid reliability and are the most difficult to manage in real-time operations.

The chart below, which is based on eDART data, shows the trending of forced, maintenance and planned outages through the early January 2018 cold weather period. As the cold weather progressed through the week of Jan. 1, there was an increase in forced/unplanned outages, with outage rates peaking on Saturday morning, Jan. 6, HE 09, and then again on Sunday morning, Jan, 7, HE 09 when the highest forced outage peak was reached (23,751 MW). These forced outage peaks were not coincident with the peak load for the week, which occurred on Friday Jan. 5, HE 19.

After the Sunday morning HE 09 forced outage peak on Jan. 7, forced outages dropped off steadily through the day and continued to decrease over the next few days as temperatures moderated. Figure 12 shows that during this same period, as PJM needed less generation to meet demand, the amount of maintenance outages steadily increased, reflecting generation owners taking the opportunity to make repairs.

Figure 12. Outage Trends by Outage Classification



Forced Outages

Using eDART data, Figure 13 compares the hour with the highest forced outages experienced during the Polar Vortex to the hour with the highest forced outages experienced during the recent cold snap. Categories are based on primary fuel type as recorded in eDART and are not tied to market schedules. The "Other" category includes wind, solar, hydro and methane units. There was a significant reduction in forced outages between the two years (40,200 MW, 22 percent of total installed capacity versus 23,751 MW, 12 percent of total installed capacity).

Overall, all resources performed well during the recent cold snap (see Figure 14), with natural gas supply outages much lower, based on eDART information. In addition, the lower impact of wind chill across the RTO resulted in less predominant freezing issues than 2014. For 2018, these figures were not driven by the loss of a few larger units, but rather a diverse combination of full outages and partial reductions across many generators.

Figure 13. 2014 and 2018 Forced Outages by Fuel Type

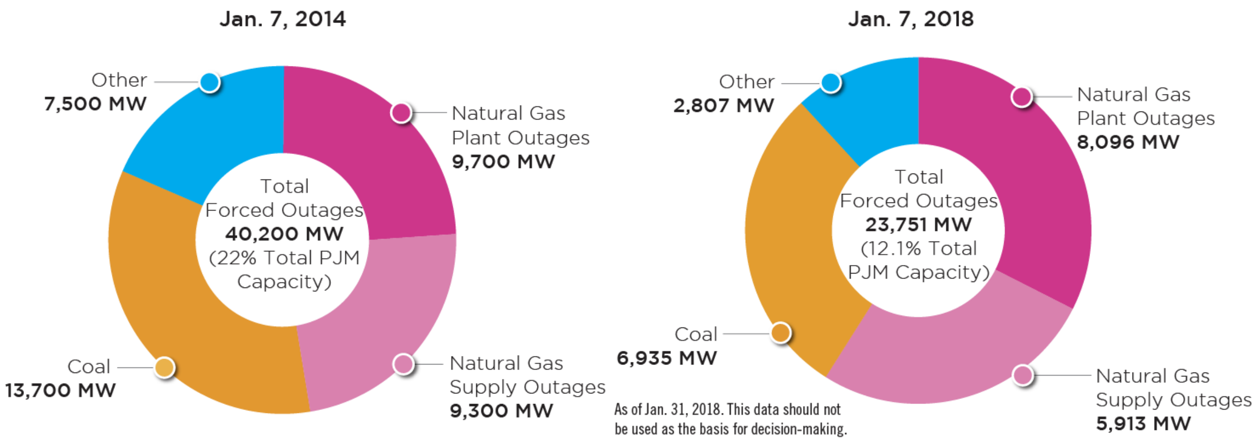
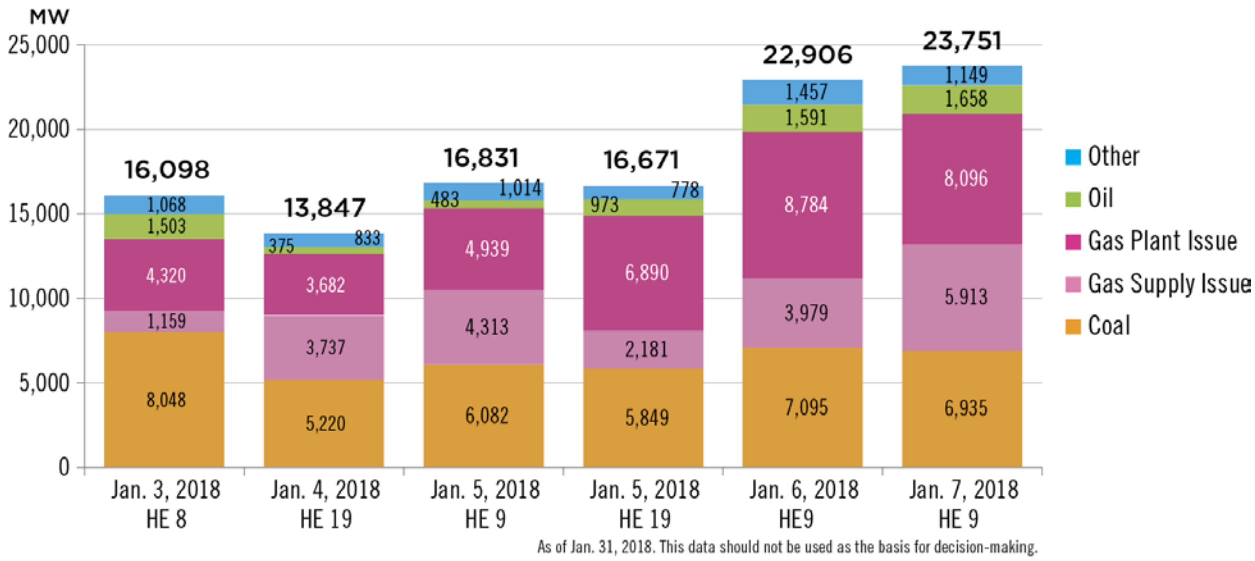


Figure 14. Outages by Fuel Type, Jan. 3–Jan. 7, 2018, Peaks



Forced Outages due to Fuel Supply Issues

To further evaluate the impact of fuel supply issues on forced outages, Figure 15 uses eDART data to show forced outages due to fuel supply issue, by fuel type. Gas supply issues were the largest in this assessment, particularly the weekend of Jan. 6 and Jan. 7, as temperatures reached their lowest points and pipeline capacity restrictions of varying degrees were in place across all pipelines serving PJM generation. PJM uses "gas supply issue" to refer to a generator outage that was due to lack of natural gas fuel supply, which could be due to a number of varying circumstances. Gas supply issues include transportation restrictions and interruptions as well as spot gas commodity availability.

Data obtained through generator outreach indicates that about 28 percent of combined coal and oil units (by ICAP MW) with on-site fuel inventories reported issues with fuel resupply due to fuel transportation constraints. For coal-fired units, the most frequently reported transportation issues were barge resupply delays due to frozen rivers and increased barge traffic. For oil units, the most frequently reported transportation issues were truck resupply delays due to reduced availability of fuel trucks at bulk terminals and road closures. To a lesser extent, barge resupply delays due to frozen rivers were also reported.

Coal supply issues were also reported as "coal quality" issues and these "coal quality" issues are mostly freezing issues that occur in the conveyance of coal from the pile to the boiler. The "other" category is primarily landfill gas and hydroelectric.

Figure 15. Forced Outages Due to Fuel Supply Issue, by Fuel Type

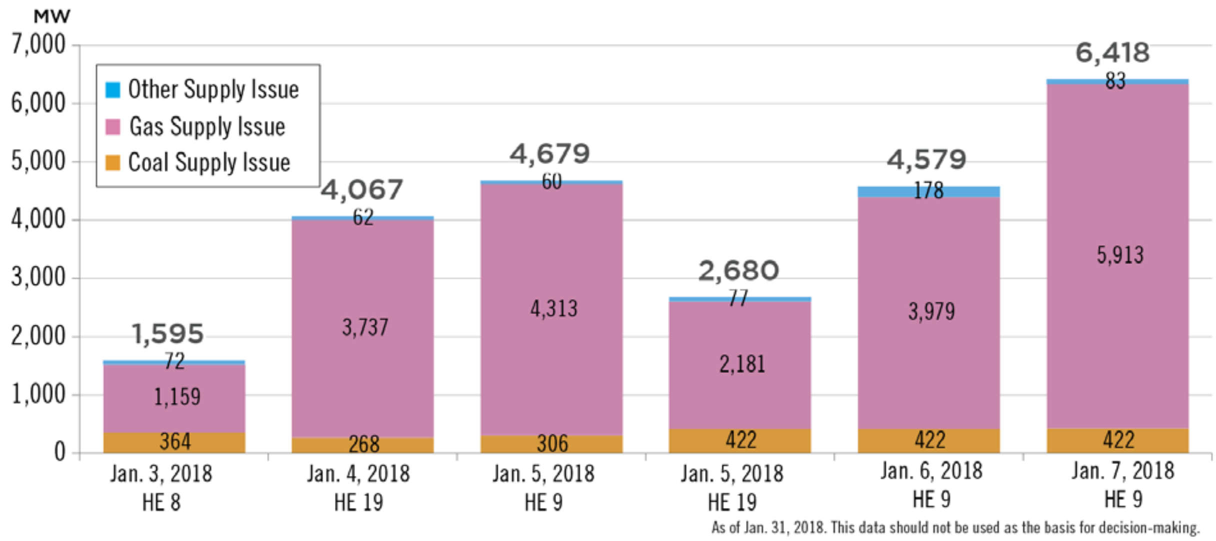
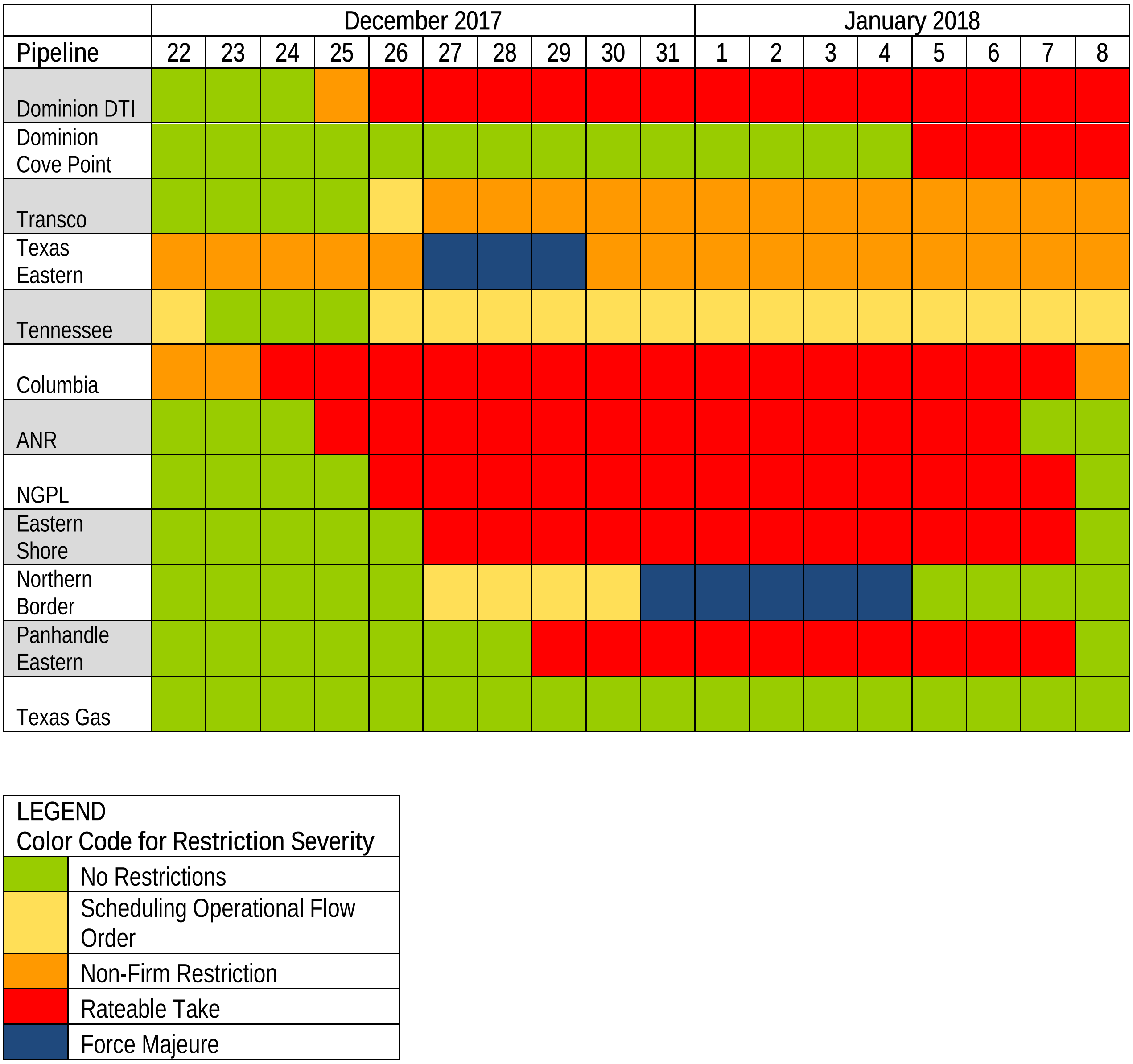


Figure 16 provides an overview of the active interstate pipeline restrictions that were in place during the period from Dec. 22, 2017 through Jan. 8, 2018. The pipelines listed in the chart are supplying the majority of gas-fired generation across the PJM footprint. While several pipelines did have multiple restriction types in place on any given day, the chart reflects the most impactful restrictions to generation. Generators holding non-firm pipeline capacity were at the highest risk over the duration of these restrictions. There were no reported firm capacity restrictions during this period, and all force majeure events were related to generators with interruptible capacity.

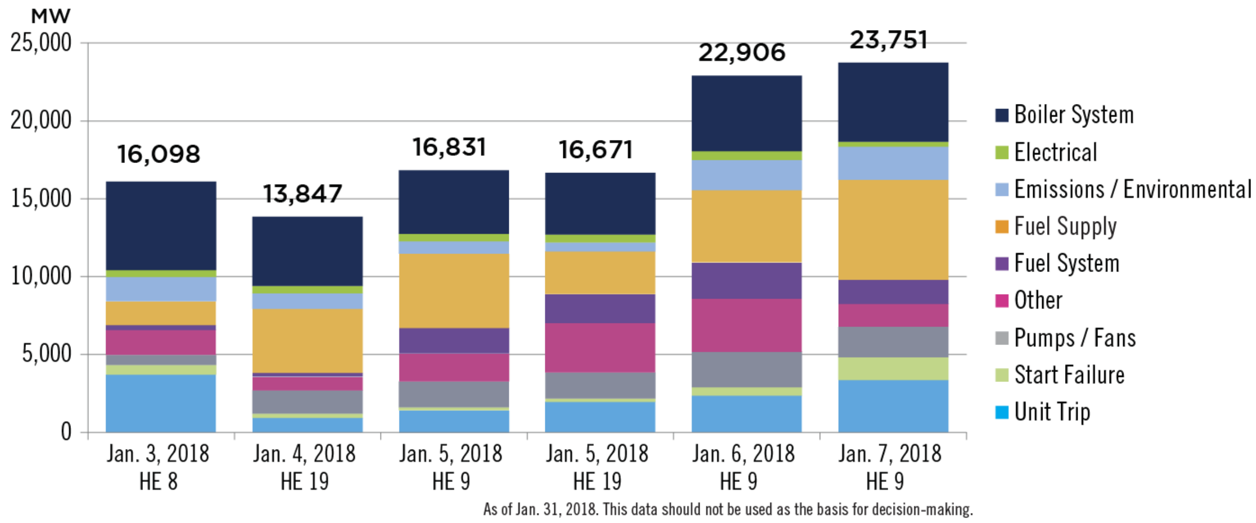
Figure 16. Active Interstate Pipeline Restrictions, Dec. 22, 2017—Jan. 8, 2018



Forced Outage Causes

Figure 17 uses eDART data to show a more detailed breakdown of the forced outages across the early January 2018 cold weather period. The eDART data indicates that boiler systems and fuel supply were the predominant forced outage causes. The “Other” category includes any outage cause type where the outage did not fall cleanly into another group or where detailed information was not available. The outage causes were distributed across a large number of units, as opposed to a small number of larger units.

Figure 17. Forced Outage Causes

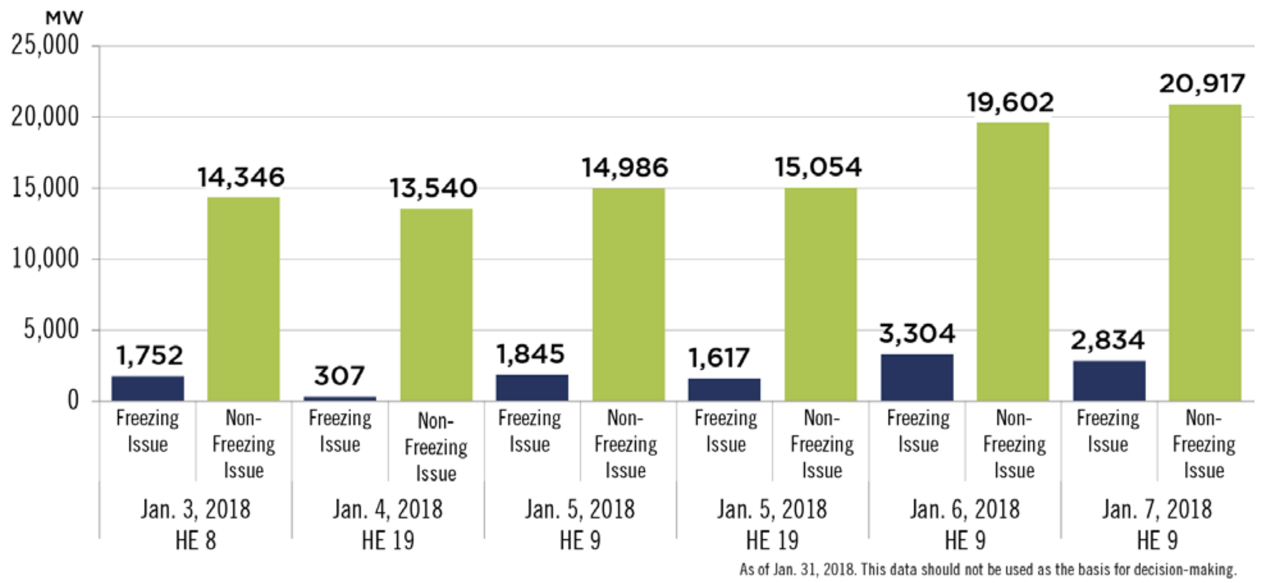


Freezing-Related Issues

Weather-related outages that may have been caused by extreme cold temperatures were significantly reduced in 2018. These issues include freezing of fuel-handling systems, electrical systems and other auxiliary systems. Some examples are issues due to frozen intake water, frozen transmitter equipment or icing on wind turbine equipment.

Improved performance over 2014 is partially due to higher temperatures and partially due to better preparation by generation owners to ensure appropriate freeze protection of equipment. The 98 percent response rate of GOs in implementing a generator winter preparation checklist contributed to improved preparation and performance.

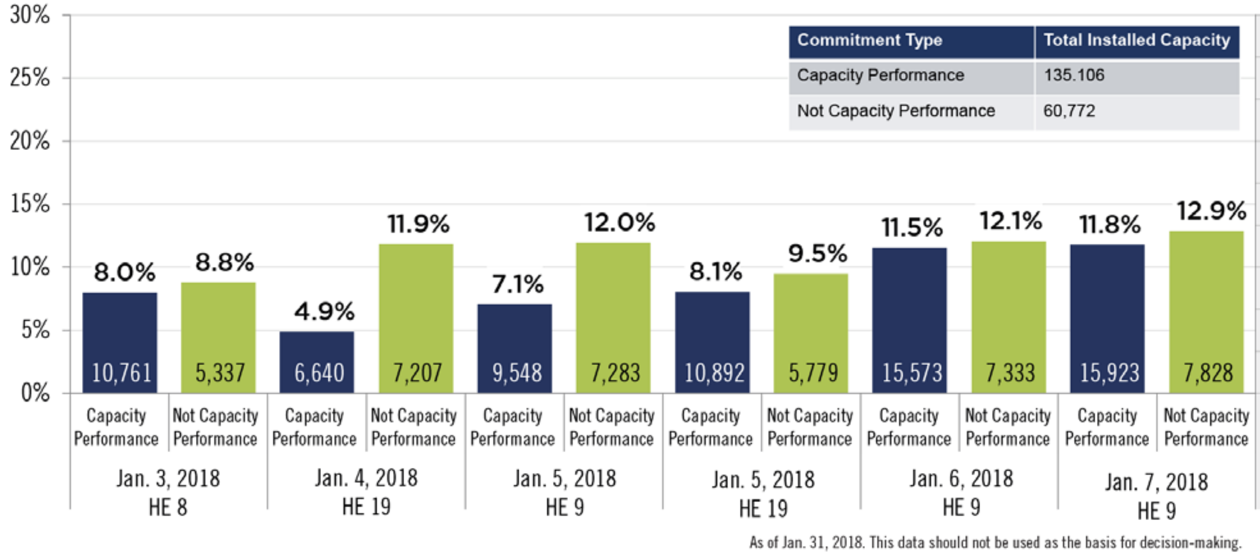
Figure 18. Freezing-Related Issues



Performance of CP vs. Non-CP Units

In order to obtain an assessment of Capacity Performance (CP) units and non-Capacity Performance units, PJM reviewed eDART forced outage data for all generation resources based on commitment type, and ICAP within each commitment type across the cold weather period. Overall, the performance of CP units was better than performance of non-CP units between Jan. 3 and Jan. 7, the coldest days of the recent cold snap.

Figure 19. Forced Outages by Commitment Type, Jan.3—Jan.7



Looking at a similar analysis by fuel type (and in comparison to the 2014 Polar Vortex), in Figure 20, the gas fuel type shows improved results for CP resources. When compared to 2014, this could be an indication that gas CP was better prepared through increased firmness of transportation capacity and supply, along with a greater diversity of natural gas supply resources and delivery options.

The operational data on outage performance for both coal and oil resources implies that there was no improvement for CP resources, and further analysis is required to confirm whether most CP resource investments have been focused on firming up supply vs. plant equipment improvements.

Overall, the forced outages by each generation fuel type were fewer in the cold snap than during the Polar Vortex peak (Jan. 7, 2014 HE8), as shown in Figure 20.

Figure 20. Fuel Type Assessment of Forced Outages by Commitment Type

	Jan. 7, 2014 HE 8		Jan. 3, 2018 HE 8	Jan. 4, 2018 HE 19	Jan. 5, 2018 HE 9	Jan. 5, 2018 HE 19	Jan. 6, 2018 HE 9	Jan. 7, 2018 HE 9
Coal	18.6%	Capacity Performance	13.3%	9.0%	11.3%	10.6%	12.9%	12.4%
		Non-Capacity Performance	13.3%	7.6%	6.6%	7.0%	8.5%	8.7%
Gas	32.7%	Capacity Performance	7.1%	4.5%	8.2%	10.8%	16.9%	18.3%
		Non-Capacity Performance	7.7%	19.8%	19.9%	14.6%	17.2%	19.4%
Oil	27.3%	Capacity Performance	26.7%	5.3%	6.9%	18.8%	22.6%	21.5%
		Non-Capacity Performance	13.3%	5.3%	6.6%	6.5%	22.0%	25.9%
Other	15.2%	Capacity Performance	0.9%	0.7%	0.7%	0.5%	1.9%	1.7%
		Non-Capacity Performance	4.9%	3.9%	5.0%	4.0%	5.0%	3.4%

Gas-Electric Coordination

In order to maintain system reliability, PJM has embarked on a process to operationalize potential natural gas contingencies across the PJM footprint. This process is driven by PJM's increased reliance on natural gas and is consistent with concerns raised by industry initiatives such as the 2016 and 2017 ERO (NERC) Reliability Risk Priorities reports.

PJM created procedures for normal and for conservative operations, which ensured operators had a clearly defined process to address gas pipeline impacts on generator availability and the PJM RTO in time for the 2017–2018 winter season. This approach is documented within various PJM manuals.

Under the following conditions, PJM follows the defined procedures and operates to reflect the impact of gas pipeline contingencies on the PJM RTO:

- Severe temperatures/weather
- Pipeline outages (maintenance, force majeure events)
- External cyber/physical security threats

Gas-Electric Contingencies

A total of 63 contingencies were created to simulate the loss of pipelines, compressor stations and LDCs within the PJM footprint, of which 18 were focused on the LDCs. These contingencies were developed as part of PJM's efforts to operationalize gas contingencies, and PJM is continuing to work with the interstate pipelines to refine these contingencies. During the 10 days that cold weather alerts were issued between Dec. 27, 2017 and Jan. 17, 2018, a subset of these gas-electric contingencies were evaluated to determine the potential impact of PJM's natural gas generators on the PJM RTO transmission system and required generation reserves.

The corresponding risk assessments during this period indicated no reliability issues for the loss of compressor stations or LDCs within the PJM footprint.

The largest gas contingency observed during this period totaled approximately 2,000 MW representing a potential loss of a major compressor station impacting a cluster of three generating units. No additional generator reserves were required due to the limited size of this contingency. The total operating reserves averaged approximately 15,000 MW during the cold weather period and exceeded the gas generation loss by a large margin.

PJM continues to engage interstate pipelines and LDCs to review gas pipeline contingencies to ensure PJM's assumptions and conclusions about pipeline operations and redundancies are valid.

Markets

PJM performed a comparative analysis of the 2014 Polar Vortex and 2017–2018 cold snap market prices. This analysis compared the 12 consecutive highest-priced days of both periods, which were:

- Jan. 20–31, 2014
- Dec. 28, 2017–Jan. 8, 2018

Locational Marginal Pricing (LMP) in the Polar Vortex vs. Cold Snap

Real-time prices were $10/MWh lower during the recent cold snap than during the 2014 Polar Vortex, and day-ahead prices were approximately $90/MWh lower (see Figure 21).

Figure 21. PJM RTO Average Real-Time and Day-Ahead LMP*

	2017/18			2014		
	Real-Time	Day-Ahead	Difference	Real-Time	Day-Ahead	Difference
Total LMP	$135	$125	-$10	$147	$212	$65
Energy	$135	$120	-$15	$147	$211	$64
Congestion	-$0.1	$4.0	$4.1	$0.1	$1.2	$1.1

**Note: Losses are not shown.*

Not only were prices in general lower during the recent cold snap, day-ahead and real-time prices were much more closely aligned. Day-Ahead LMP and energy prices differed by $10/MWh and $15/MWh from real-time, respectively, compared to a difference of approximately $65/MWh in 2014. Figure 22 depicts the convergence of day-ahead/real-time price during the recent cold snap compared to 2014.

Figure 22. Real-Time and Day-Ahead LMP Comparison

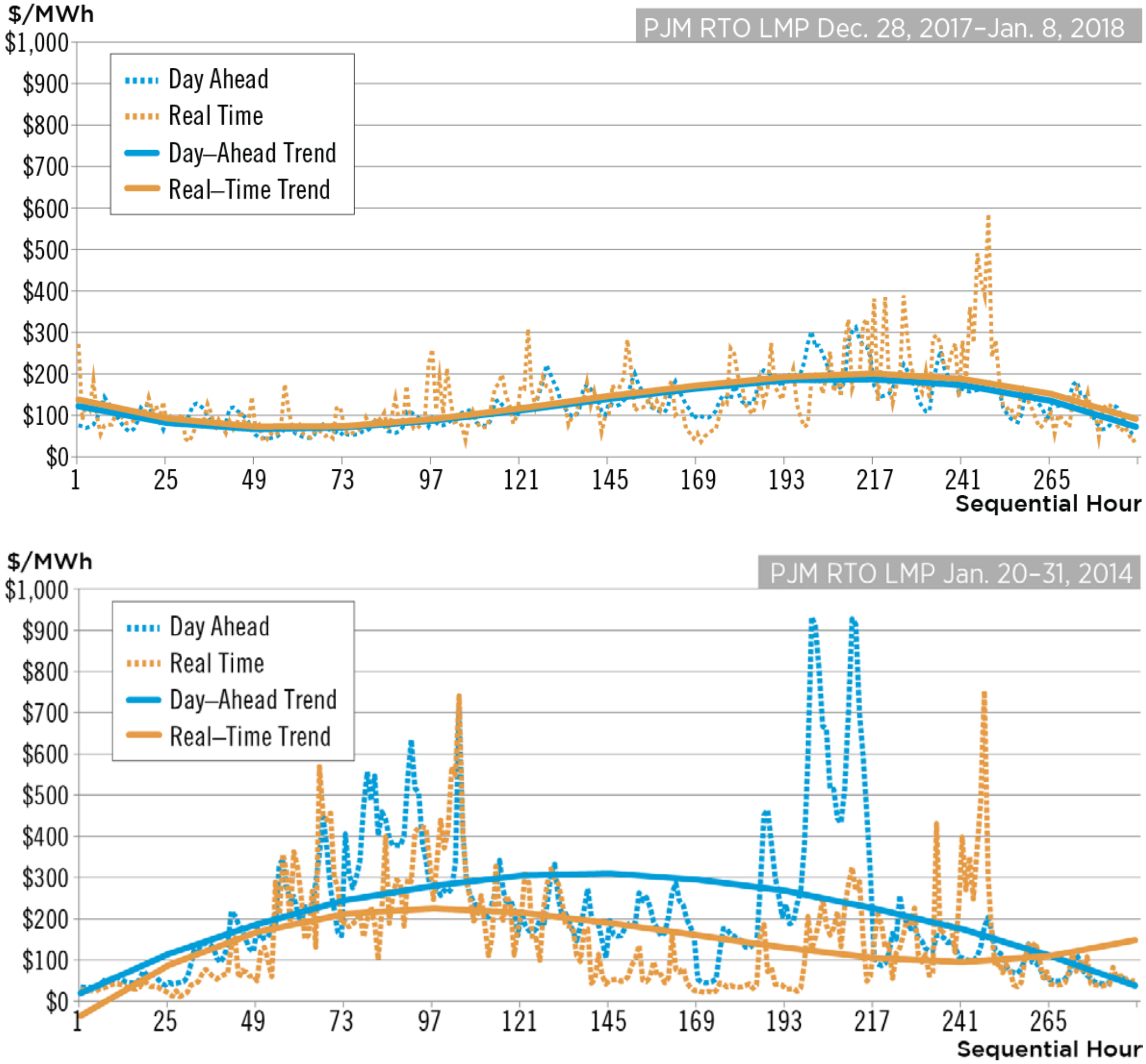


Figure 22 compares the average LMPs between the Day-Ahead and Real-Time markets and demonstrates the convergence between the two markets. The top portion of the graphic shows the comparison during the recent cold snap and the bottom portion shows the comparison during the Polar Vortex. In addition to the LMP data, trend lines are provided to show the general trend of the day-ahead and real-time LMPs.

The difference between the day-ahead and real-time average LMP during the recent cold snap is much smaller than it was during the 2014 Polar Vortex. This convergence indicates tighter alignment of operating expectations between day-ahead and real-time recently as compared to the Polar Vortex.

Figure 23 shows the location, by zone, of the highest-priced components of LMP at load pricing-nodes for the two periods indicated above in addition to the highest hourly total LMP during the period. The magnitude and location of the maximum real-time LMP and the associated congestion price were similar in 2014 and in the recent cold snap. These prices were driven mostly by congestion, though energy was priced considerably higher during the recent cold snap, compared to 2014.

Figure 23. Maximum Real-Time and Day-Ahead LMP

	Real-Time			Day-Ahead		
2014	Price	Time	Zone	Price	Time	Zone
Total LMP	$2,257	1/29/14:01	AEP	$1,500	1/23/14:07	DPL
Energy	$751	1/30/14:06	N/A	$934	1/28/14:07	N/A
Congestion	$2,129	1/29/14:12	AEP	$904	1/23/14:06	APS
2018						
Total LMP	$2,338	1/4/18:22	AEP	$1,977	1/8/18:17	PENELEC
Energy	$586	1/4/18:21	N/A	$295	1/5/18:19	N/A
Congestion	$2,185	1/4/18:22	AEP	$1,842	1/8/18:17	PENELEC

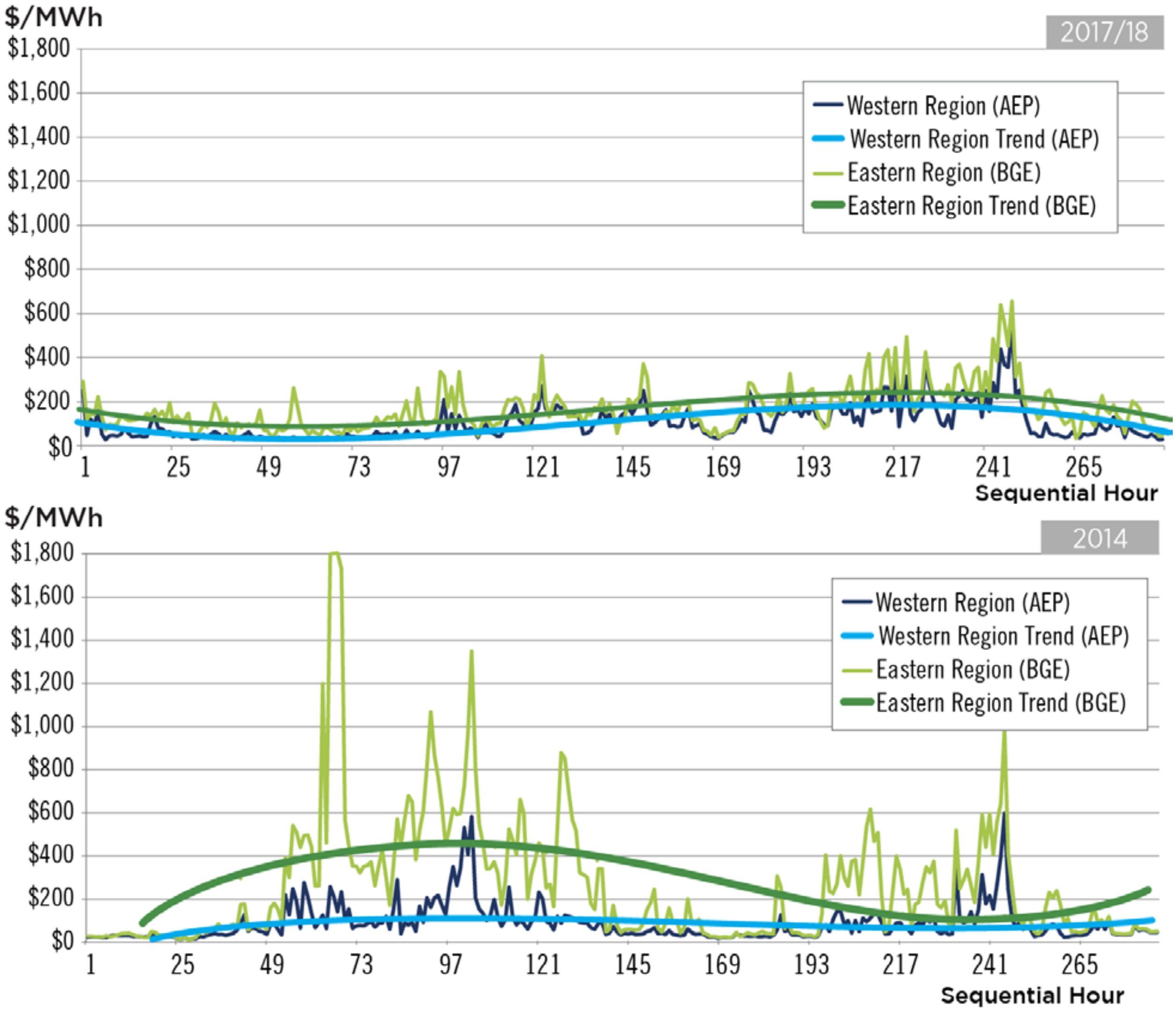
Figure 24 shows that the price differences between the western and eastern regions of PJM were much smaller during the recent cold snap than in 2014. The average price in the east during the cold snap was approximately $100/MWh lower than during the 2014 Polar Vortex, as was the average east-west price difference. Maximum prices were also much lower during the recent cold snap as well. In the east, maximum prices were more than $1,100/MWh lower than the 2014 Polar Vortex, and the maximum west-east price difference was approximately $1,400/MWh lower.

Figure 24. Real-Time Western and Eastern Region LMP

	Western Region (AEP)			Eastern Region (BGE)			Eastern-Western		
	2017/18	2014	Difference	2017/18	2014	Difference	2017/18	2014	Difference
Min	$28	$12	$16	$35	$12	$22	-$45	-$7	-$38
Mean	$106	$89	$17	$170	$261	-$91	$64	$171	-$107
Max	$546	$598	-$52	$656	$1,804	-$1,148	$227	$1,660	-$1,433

Besides lower average prices and smaller west-east price differences, prices were also much less volatile during the recent cold snap. The dashed trend lines in Figure 25 are a measure of volatility and show that prices were much less volatile during the recent cold snap than in 2014, and also show much-improved day-ahead/real-time alignment.

Figure 25. Real-Time Western and Eastern Region LMP



Congestion

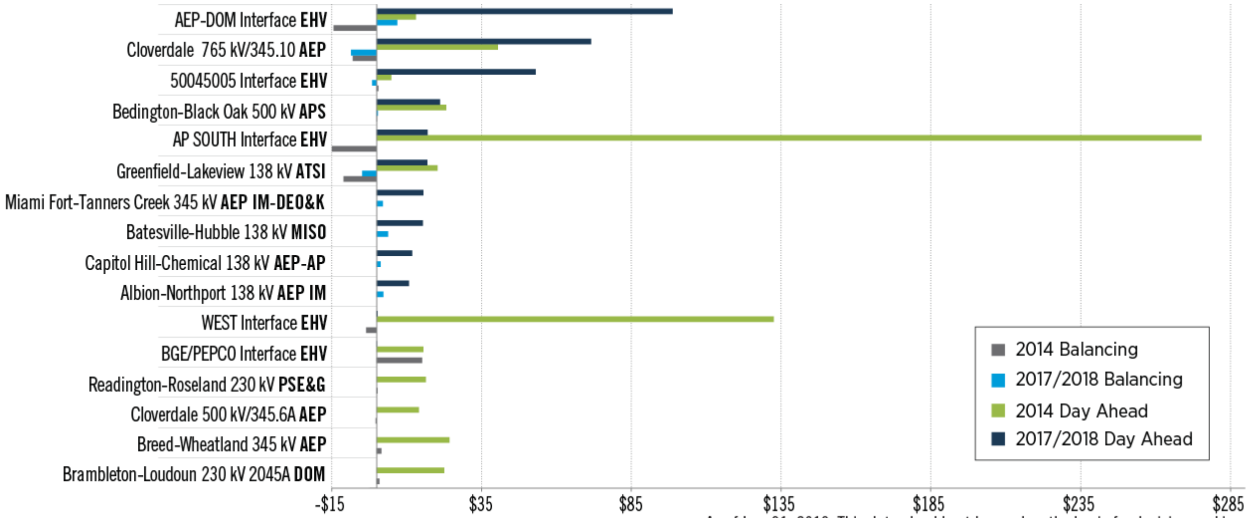
PJM's comparative analysis showed that both day-ahead and balancing congestion were much lower in the recent cold snap than in the 2014 Polar Vortex. The cold snap day-ahead congestion was $435 million (Figure 26), which is $275 million less than the Polar Vortex ($720 million). Balancing totaled approximately $3 million in the recent cold snap, which was $68 million more than in the 2014 Polar Vortex. The decrease in negative balancing congestion also is an indicator of better alignment between the Day-Ahead and Real-Time markets in the recent cold snap than in the Polar Vortex.

Figure 26. 2017–18 Cold Snap vs. 2014 Polar Vortex Congestion

	Day-Ahead ($M)			Balancing ($M)		
	2014	2017/18	Delta	2014	2017/18	Delta
Study-Period Total	$720	$435	-$285	-$65	$3	+$68
Top Constraints	$600	$330	-$270	-$35	$2	+$37
Major Interfaces	$505	$255	-$250	-$25	-$3	+$22

PJM also compared the most heavily congested facilities of the recent cold snap with those of the 2014 Polar Vortex. Eight facilities restricted transfers during both events, and six of those were reactive transfer interfaces. Figure 27 shows that the APSOUTH and West Interfaces accounted for 57 percent of 2014 Polar Vortex congestion but only 4 percent of the cold snap. Congestion during the cold snap was heaviest on the AEP-DOM and 5004/5005 interfaces and Cloverdale 765/345, which together accounted for 50 percent of total congestion. Balancing congestion was significantly lower during the recent cold snap and was positive for many facilities.

Figure 27. Significant Transmission Constraints Comparison



As of Jan. 31, 2018. This data should not be used as the basis for decision-making.

Gas Price Analysis

For the most part, gas market prices were more affected than the electric market, most significantly on Jan. 4 and Jan. 5, 2018. The coldest day of the event ended up being on the weekend after a prolonged cold week, which means loads were lower than they would have been during the week. As a reference, oil and coal prices were approximately $19/MMBtu and $2.50/MMBtu in 2014 and $12.50/MMBtu and $2.50/MMBtu in 2018.

The cold weather had a significant effect on the natural gas market pricing, specifically in the northeast pipeline pricing hubs, where gas is at the end of the gas-piping network, where supply becomes tighter and pricing is higher. The primary gas market hubs affected were Transco Zone 6, New York and Non-New York, Transco Zone 5 and TX Eastern M-3.

For the gas market trade day of Jan. 4, 2018, with a flow date of Jan. 5, 2018, the entire northeast gas price was approximately $90/MMBtu. The midpoint of the primary impacted gas market hubs was approximately $122/MMBtu, with trades in excess of $150/MMBtu.

These high gas prices had an impact on gas-fired generator offers within the area affected by the high gas prices. PJM uses the heat rates in Figure 28 to determine high-level impacts on offers and to assess if offers are reasonable and following the natural gas market prices. The first two rows demonstrate the normal range of gas prices as they translate to generator costs.

Figure 28. Estimated Cost-Based Offer Level vs. Natural Gas Prices

Hub Price	Combined Cycle 7.5 Heat Rate	Steam 10.0 Heat Rate	Combustion Turbine 15.0 Heat Rate
$5.0/MMBtu	$37.5/MWh	$50.0/MWh	$75/MWh
$20.0/MMBtu	$150/MWh	$200/MWh	$300/MWh
$75.0/MMBtu	$562.5/MWh	$750/MWh	$1,125/MWh
$100.0/MMBtu	$750/MWh	$1,000/MWh	$1,500/MWh
$125.0/MMBtu	$937.5/MWh	$1,250/MWh	$1,875/MWh

The cold snap had an unprecedented impact on gas market prices and pushed them well into the higher range. As shown in the last three rows of Figure 28, using a straight heat-rate multiplied by delivered fuel cost, prices were capable of pushing offers into the $1,000/MWh range.

In all, 94 units entered cost-based offers with segments greater than or equal to $1,000/MWh (83 units in the Day-Ahead Market and 11 units in the Real-Time Market). However, these prices did not directly influence the Day-Ahead or Real-Time Energy markets, as the $1,000/MWh segments did not set price in either market.

Generator Uplift

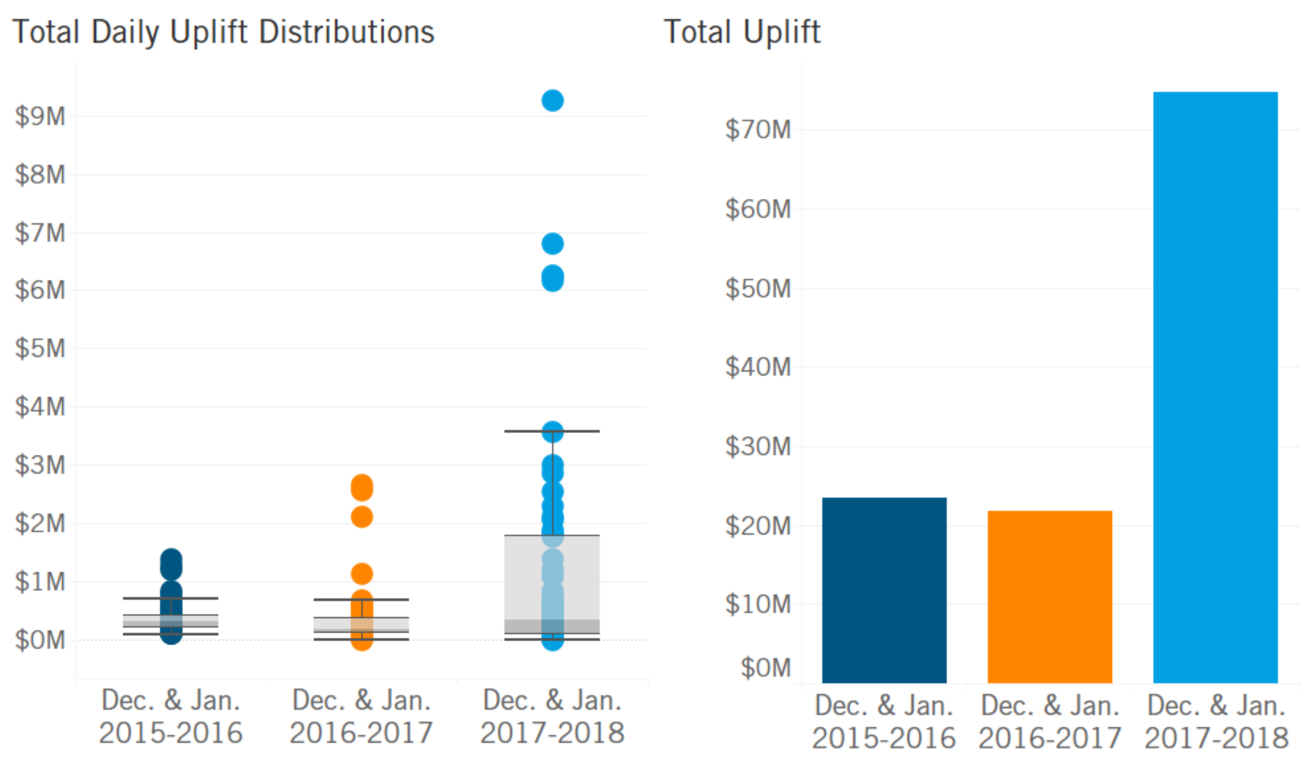
PJM provides uplift payments to resources that have been scheduled by PJM, follow PJM's dispatch instructions, and do not collect enough revenues via locational marginal prices to recoup their offered costs. Generators and demand resources are eligible for uplift and receive full recovery of their offered costs associated with the specific dispatch instructions.

The level of uplift may increase as the need for more supply increases during periods of high demand. This is particularly true when weather conditions are extreme. In these cases, actions may be taken by PJM operators to maintain reliability that are not reflected in the market-clearing price. In other words, PJM may schedule resources for reliability purposes in anticipation of future load levels and to ensure that sufficient reserves are available to cover potentially unforeseen events, when those resources are not otherwise scheduled to run. Those resources are scheduled by PJM because they are needed to serve load but are being paid outside of the market, which results in an inefficient market price signal. The better result would be for these resources, as much as possible, to cover the cost of their offers through transparent market clearing prices.

During the cold snap, PJM experienced a significant increase in uplift charges as seen below. Over the last several years, uplift charges have averaged approximately $389,000 per day in PJM. During the peak days of the cold snap, uplift charges averaged over $4.3 million per day and totaled $47 million. The day with the highest amount of uplift reached nearly $9 million.

This significant increase in uplift (see Figure 29) is a clear indication that the resources operating at PJM's direction were not recovering the total costs of their offers through the market. This result indicates the need to address this issue in a timely manner to ensure that all operator actions are reflected in energy market prices. As PJM operator actions are taken to ensure reliable operations on a day-to-day basis and at the most critical times, when the systems is stressed by weather events such as the recent cold snap, it is expected that energy and reserve prices reflect the cost of reliably serving load to ensure the market remains efficient and transparent.

Figure 29. Uplift Distributions and Total Uplift Comparison



PJM received cost-based energy offers greater than $1,000/MWh for the operating days Jan. 3, 2018, through Jan. 7, 2018. Due to system conditions, resources with offers greater than $1,000/MWh did not receive Day-Ahead awards or run times during each of the operating days of the cold snap.

Balancing Operating Reserve Credits

Balancing Operating Reserves (BOR) are incurred in order to guarantee full recovery of costs associated with PJM requesting resource(s) to operate at PJM's direction. The uplift payments are not included in the Day-Ahead and Real-Time markets and are accounted for on a daily rate basis in dollars per megawatt hour based on Real-Time Market deviations.

Deviations are categorized as generation not following PJM dispatch instructions, demand not following Day-Ahead commitment, cleared increment offers and purchase transactions, cleared demand bids, decrement bids and sales transactions.

BOR credits are further categorized by reliability credits and deviation credits and are based on how the resource is committed. During the cold snap, BORs were $25.4 million, with the greatest daily BORs on Jan. 1, 2018, and Jan. 2, 2018. The high BORs for Jan. 1 were primarily due to PJM requesting combustion turbines and steam units to operate in real time in order to monitor and control the transfer flows on the 5004/5005 transfer interface and AEP-DOM transfer interface. Figure 31 shows the daily BOR credits provided by day and unit type during the cold snap.

Figure 30. Total Lost Opportunity Cost and Operating Reserve, Dec. 28, 2017—**Jan.** 7, 2018

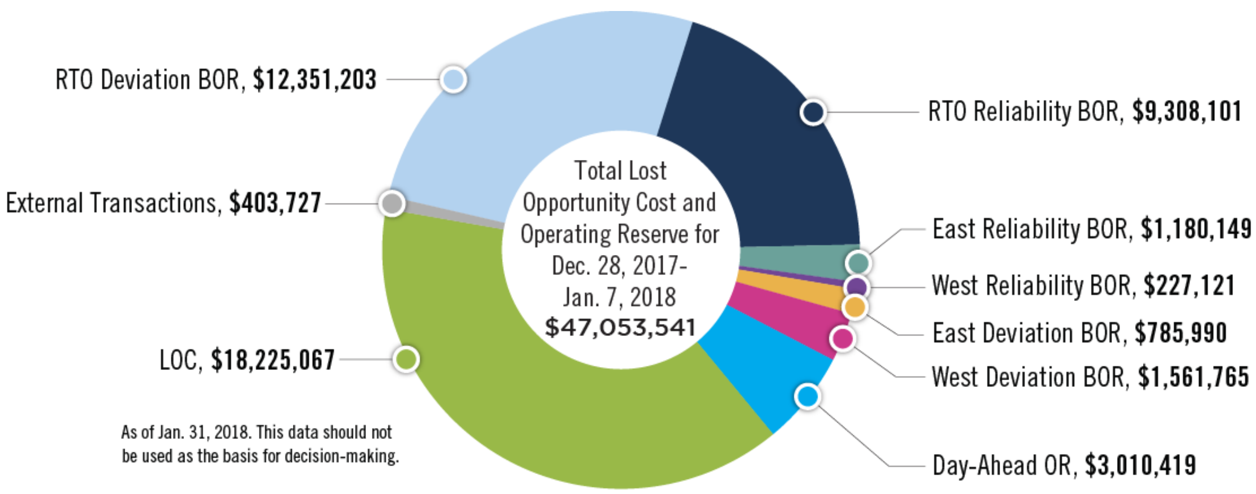
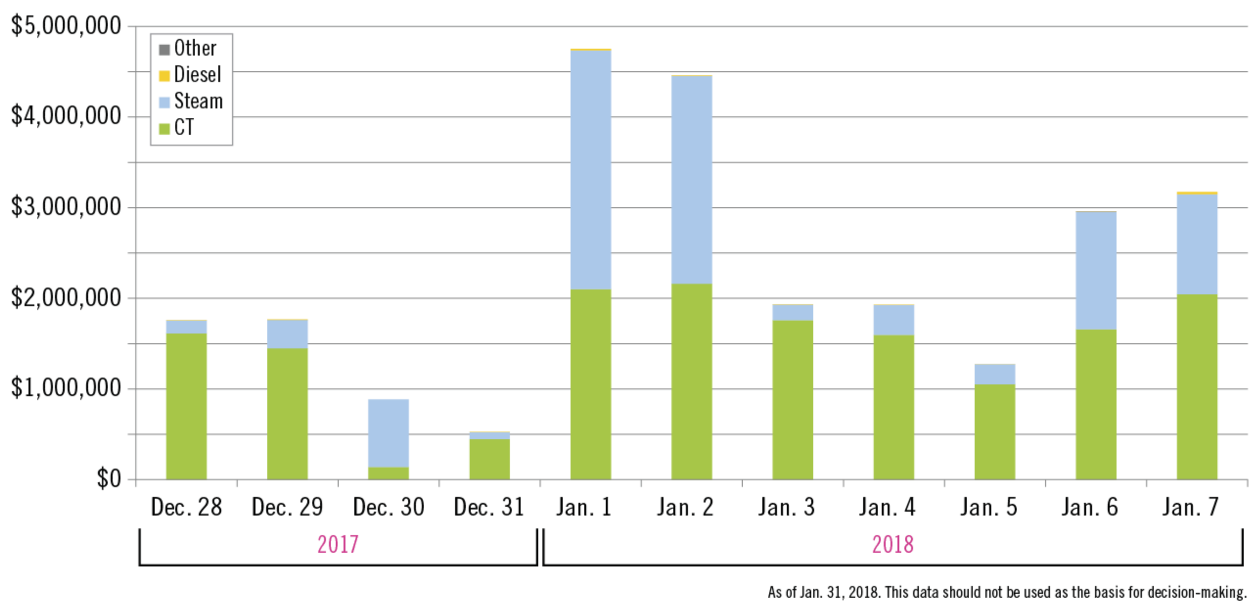


Figure 31. Balancing Operating Reserve Credits, Dec. 28, **2017—**Jan. 7, 2018

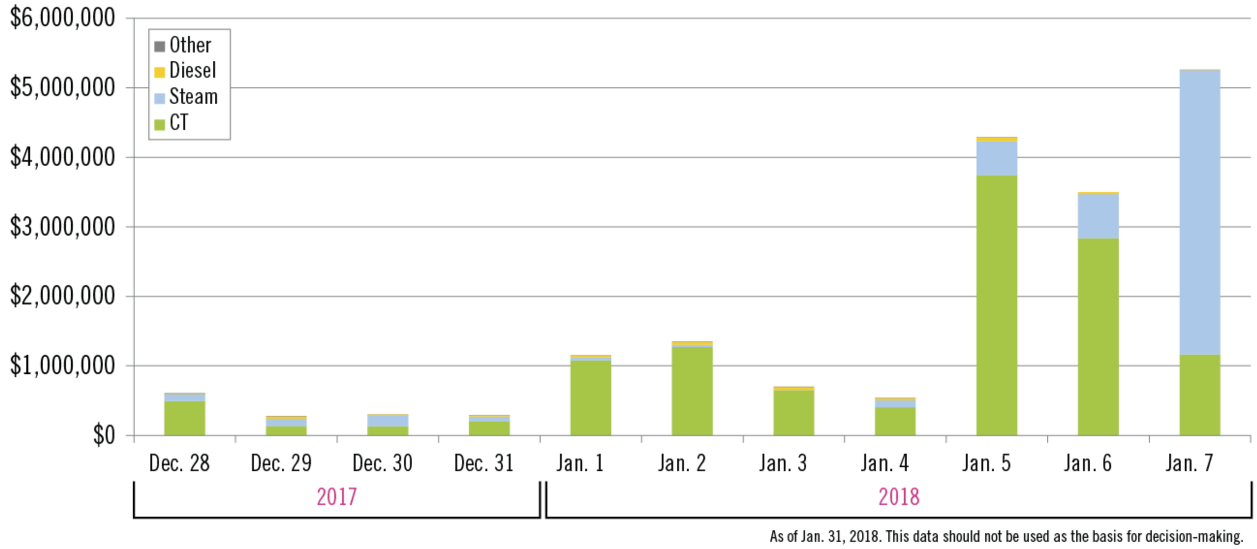


Lost Opportunity Cost

A resource incurs a lost opportunity cost (LOC) credit during periods when it foregoes profit by following PJM's dispatch instructions. This can occur if a resource is manually dispatched down when prices are high or when a resource is not requested to run per its day-ahead commitment.

LOC credits totaled $18.2 million during the cold snap, with the highest daily LOC being $5.3 million on Jan. 7, 2018. This was primarily due to out-of-merit, manual dispatches of steam units to mitigate transmission constraints, AEP-DOM transfer interface limits, and day-ahead committed resources not operating in real time due to real-time reactive transfer limits and economics.

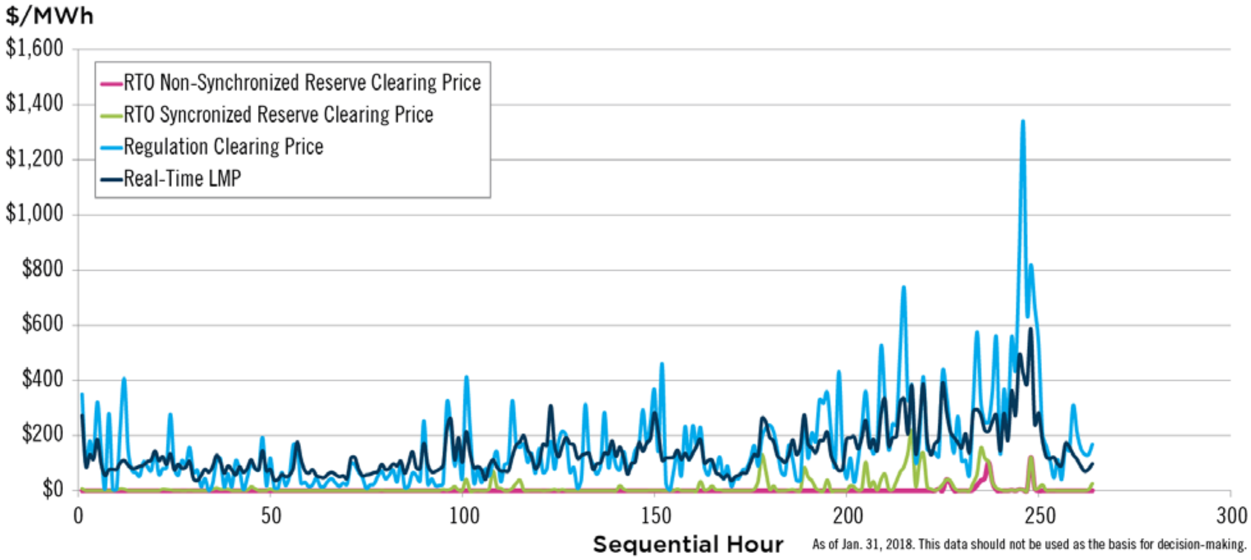
Figure 32. Lost Opportunity Cost Credits, Dec. 28, **2017—**Jan. 7, 2018



Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserves

When day-ahead and real-time LMPs increase, there are usually higher clearing prices for regulation and synchronized and non-synchronized reserves. This occurs because the LOC incurred by a resource by providing ancillary services instead of providing energy is included in the market-clearing price. Therefore, as LMPs increase, LOC increases and the ancillary service market clearing prices increase. Clearing prices indicated the same trend throughout the cold snap. See Figure 33 for more details.

Figure 33. Hourly Clearing Prices, Dec. 28, 2017—Jan. 7, 2018



The highest average regulation market clearing prices (RMCP) occurred on Jan. 6 and Jan. 7, during the cold snap. This aligns with the highest average LMPs during the same period. On Jan. 7, 2018, PJM's RMCP was at its highest clearing price — $1,338.04 in HE06. The high RMCP was due to high LMP (as described above).

PJM issued three Synchronized Reserve Events for the entire PJM RTO region during the period of Dec. 28, 2017, through Jan. 7, 2018. All three Synchronized Reserve Events met the NERC Disturbance Control Standard requirement[5] with a minimum duration of 7 minutes and a maximum duration of 13 minutes. All three events received adequate Tier 2 response, with resources responding quickly and with highest Synchronized Market clearing price of $40.48/MWh during the Synchronized Reserve Events.

The Security Constrained Economic Dispatch (SCED) engine co-optimizes energy and reserves. SCED dispatch signals are sent to generating resources to maintain both Contingency (Primary) and Synchronized (Spinning) 10-minute reserve requirements. These reserves are available for deployment to recover from the loss of generation and restore system frequency in accordance with NERC BAL-001-2 standards.

During the cold snap, PJM did not experience reserve shortage conditions. Sufficient reserves were available to meet both the contingency (primary) and synchronized reserve requirements as illustrated below. Figure 34 compares the contingency (primary) reserve values to the Contingency reserve requirement and Figure 35 compares the synchronized reserves to the synchronized reserve requirement.

[5] http://www.nerc.com/files/bal-002-0.pdf

Figure 34. **Contingency (Primary) Reserves, Dec. 28, 2017—Jan. 8, 2018**

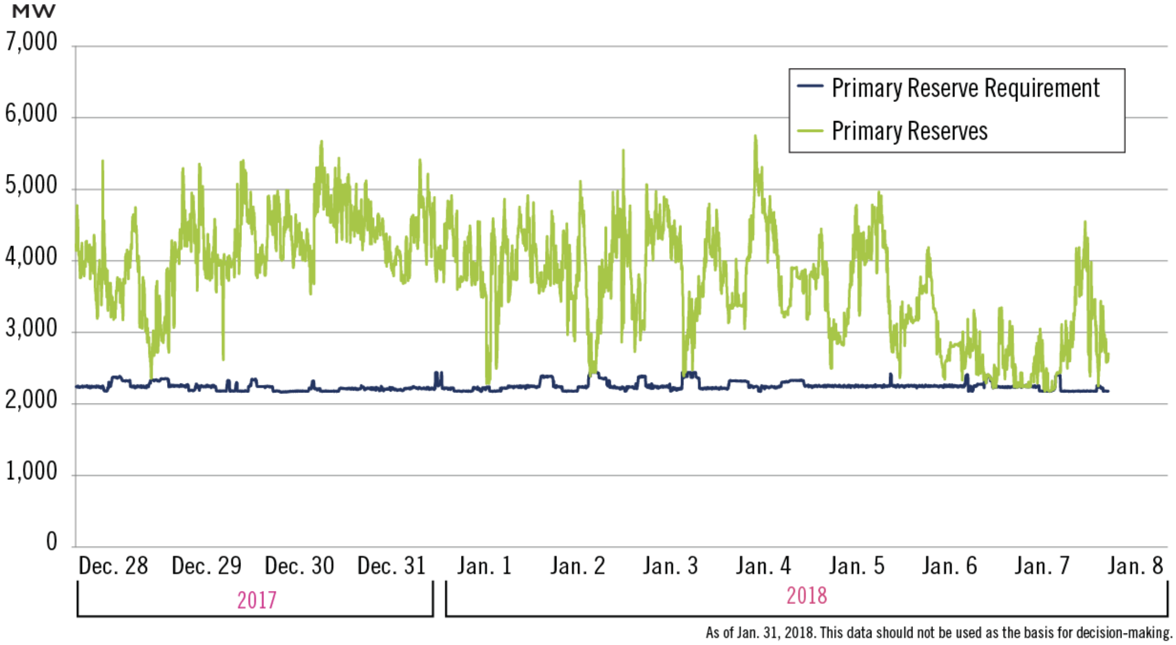
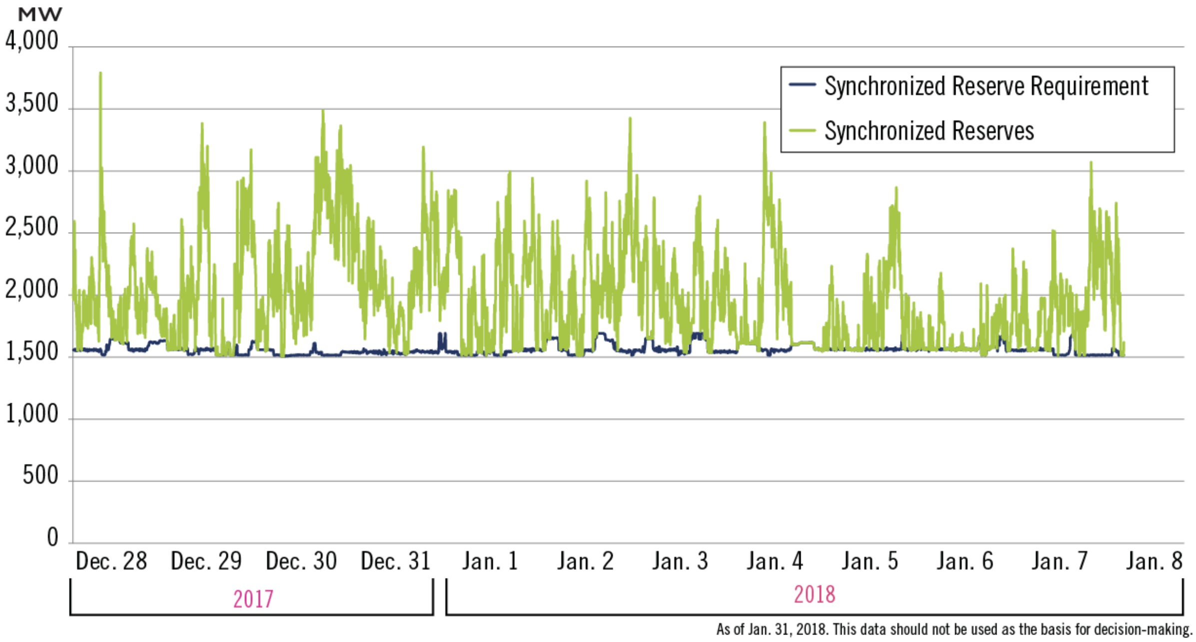


Figure 35. **Synchronized Reserves, Dec. 28, 2017—Jan.** 8, 2018



Conclusion and Next Steps

Though not as severe a test of the bulk power grid as the 2014 Polar Vortex, the recent cold snap provided insight into the robustness of the grid and the effectiveness of the changes implemented since the Polar Vortex. Thanks to the reliable operations from PJM members and operators, the system performed well in the cold snap, evidence that the grid in the PJM region remains strong, diverse and reliable.

There is, however, always room for additional improvement. PJM has noted a few areas of focus for PJM and its members.

Fuel Security

This report reflects on improvements made to cold weather preparation and gas-electric coordination. PJM needs to continue to enhance its gas-electric coordination capabilities and coordination activities to include improved contingency modeling and improved information sharing with local distribution companies. Another area of fuel security that needs additional analysis, and potentially additional tools for operators and owners, is tracking and transportation of fuel oil supplies. While oil is typically a backup resource, PJM resources used more oil during the cold snap, which stressed some resources and supplies.

Uplift and Pricing Strategy

This report highlights the spike in uplift during the recent cold snap. Over the last several years, uplift charges have been relatively low in PJM; however, during the peak days of the cold snap, uplift charges were at least 10 times higher than normal. This result will require further investigation to ensure that at the most critical times, when the system is stressed by weather events such as the recent cold snap, energy and reserve prices reflect operator actions, and therefore, the cost of serving load to the greatest extent possible. PJM and PJM stakeholders need to evaluate and implement reforms in a timely manner, including the manner in which reserves are procured and priced, enhancements to shortage pricing, and the calculation of locational marginal pricing. These issues are under discussion in the Energy Price Formation Senior Task Force. The task force is focusing on the opportunity to enhance energy market pricing so that prices accurately reflect the cost of serving load and minimize the need to recover those costs through out-of-market uplift payments.

Extended Periods of Stressed Operations

The report also highlighted the difference between the 2014 Polar Vortex and the recent cold snap. It will be prudent for PJM to further analyze the scenario of low temperatures and wind chills such as experienced during the Polar Vortex coupled with the extended duration of the recent cold snap. This analysis may inform the activities currently contemplated to enhance resilience. These include operational tools, including reserves, needed to ride through extreme prolonged events; the human factor of resilience (e.g., how the real-time operations function is staffed under extreme scenarios); degraded operations should the system have experienced more severe constraints; and the various ways to minimize stress on the system.

Appendix

Potential Changes in Market Rules

PJM is awaiting a final order from the Federal Energy Regulatory Commission (FERC) on Order No. 831, Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,[6] which may change its market rules.

As of the writing of this report, PJM is still operating under its intra-day offer market rules and ex-post (based on actual results) verification of $1,000/MWh offers. These market rules allow cost-based and price-based offers to be entered into Markets Gateway without ex-ante (based on forecasts) verification above $1,000/MWh[7] as discussed in the PJM Tariff. The Markets Gateway is a PJM tool that allows members to submit information and obtain data needed to conduct business in the Day-Ahead, Regulation and Synchronized Reserve Markets.

Summary of Current Market Rules

- Cost-based offers do not have a limit on what can be entered into Markets Gateway; however, they are capped at $2,000/MWh for setting locational marginal price (LMP). Any verified cost-based offer greater than $2,000/MWh can be made whole (per appendix D of Manual 11).
- Market-based offers are capped at the greater of $1,000/MWh or cost-based offer up to $2,000/MWh, which is the upper limit for market-based offers.

[6] https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf

[7] See the PJM Tariff, OA, Section 1.10.1A (d) (viii), https://www.pjm.com/directory/merged-tariffs/oa.pdf.