Working to Perfect the Flow of Energy

Fuel Security Analysis

Technical Appendix

December 17, 2018

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Errata
Dec. 24, 2018: Text labels on Fig. 9 were corrected, as was accompanying language on page 13.

Technical Appendix

This document is the Technical Appendix to the Fuel Security Analysis paper released by PJM Interconnection on Dec. 17, 2018. The Technical Appendix includes further technical detail and explanation of the PJM fuel security analysis, assumptions, sensitivities and results, often without the context provided in the white paper. The Technical Appendix is intended to be a companion piece to the Fuel Security Analysis paper.

Outreach and Research

Outreach

In order to adequately inform the analysis, PJM conducted extensive outreach with member organizations, industry, and research and trade organizations. The information gathered was integral to developing assumptions and overall analysis.

- **Generation Owner Surveys:** Seasonal Fuel and Emissions Surveys & Periodic Surveys.[1] These surveys are performed in advance of the winter operating season, and provide information such as detailed fuel types, on-site fuel inventory information, and firm and interruptible natural gas quantities. PJM also issued a generator survey specific to the fuel security effort to collect additional data from coal, oil, natural gas, and hydroelectric resources.[2]

- **Stakeholder Feedback:** PJM also considered stakeholder comments either submitted directly to PJM or offered during stakeholder meetings.[3]

- **Individual Generation Owner Discussions:** Discussions with individual generation owners allowed PJM to gain a better understanding of the data submitted to PJM in survey tools as well as certain operating practices such as refueling and other supply chain related processes.

- **Regulators:** Discussions were held with NERC, ReliabilityFirst and other regulators to solicit feedback on study assumptions and overall approach.

- **Government Agencies:** Discussions were held with the U.S. Department of Energy (DOE) to solicit feedback on study assumptions and overall approach. PJM will continue to work with DOE during Phase 3 of this effort.

- **Interstate Pipelines:** PJM reviewed disruption scenarios with each of the interstate pipelines to assess the viability of both the disruption scenarios as well as the potential downstream impacts.

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[1] Manual 14D, Section 7.3.5
[2] https://pjm.com/-/media/library/reports-notices/fuel-security/fsi-june-survey-questions.ashx?la=en
[3] Written comments submitted to PJM are posted on the Issue Tracking > Fuel Security page: https://pjm.com/committees-and-groups/issue-tracking/fuel-security.aspx

- **Other RTO/ISOs:** Discussions were held with neighboring RTO/ISOs regarding similar initiatives to analyze fuel security, including a detailed review of study assumptions and best approach.
- **Independent Market Monitor (IMM):** General discussions were held with Monitoring Analytics, PJM's Independent Market Monitor to solicit feedback on study assumptions and overall approach. Detailed discussions were held to review forward-looking economic profit and loss analysis as part of the escalated retirement scenarios.
- **Industry Groups:** PJM worked with several industry groups and trade organizations to gain a deeper understanding of supply chain operations, contractual options and risks. PJM also explored the potential growth of new technologies as well as projected retirements during these conversations. These industry groups and trade organizations provided both background information that helped PJM better understand the fuel supply chains and market forces behind them as well as detailed information that helped inform and validate the study assumptions.

Research

PJM reviewed studies completed by other organizations across the industry (Table 1) to understand work previously done on the topic of fuel security or resilience. PJM considered these studies to inform the scope, analysis approach and certain key assumptions ultimately selected by PJM for the purposes of its own study.

Table 1. Industry Studies Reviewed

Organization	Study	Released
The Brattle Group (Prepared for American Petroleum Institute)	Defining Reliability for a New Grid – Maintain Reliability and Resilience Through Competitive Markets	May 2018
ICF (Prepared for Nuclear Energy Institute)	The Impact of Fuel Supply Security on Grid Resilience in PJM	Jun. 2018
ISO New England	Operational Fuel Security Analysis	Jan. 2018
Institute for Policy Integrity – NYU	Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System	Apr. 2018
Lincoln Laboratory – MIT (Prepared for the Office of the Secretary of Defense)	Interdependence of the Electricity Generation System and the Natural Gas System, and Implications for Energy Security	May 2013
Monitoring Analytics	2017 State of the Market Report for PJM	Mar. 2018
National Energy Technology Laboratory (NETL), Office of Fossil Energy	ISO New England Dual Fuel Capabilities to Limit Natural Gas and Electricity Interdependencies	Apr. 2016
Natural Gas Council	Natural Gas Systems: Reliable & Resilient	Jul. 2017
North American Electric Reliability Corporation (NERC)	Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System	Nov. 2017
Quanta Technology (Prepared for American Coalition for Clean Coal Electricity)	Ensuring Reliability and Resilience: A Case Study of the PJM Power Grid	Apr. 2018

Approach and Methodology

In order to simulate the impacts of fuel security on PJM system operations, PJM chose to use Energy Exemplar's PLEXOS® Integrated Energy Model (PLEXOS). PLEXOS is a production cost model that performs both a security constrained unit commitment and security constrained economic dispatch over a given time horizon. For this analysis, PJM used hourly granularity. The software provided the needed flexibility to accurately simulate the complexities of PJM's system while developing custom constraints to simulate on-site fuel depletion and replenishment, and varying natural gas availability based on pipeline disruptions and firm or non-firm gas transportation.

Assumptions

This section includes a summary of all assumptions and sensitivities used in the analysis (Table 2), as well as further technical details on the assumptions and sensitivities.

Table 2. Assumptions Summary

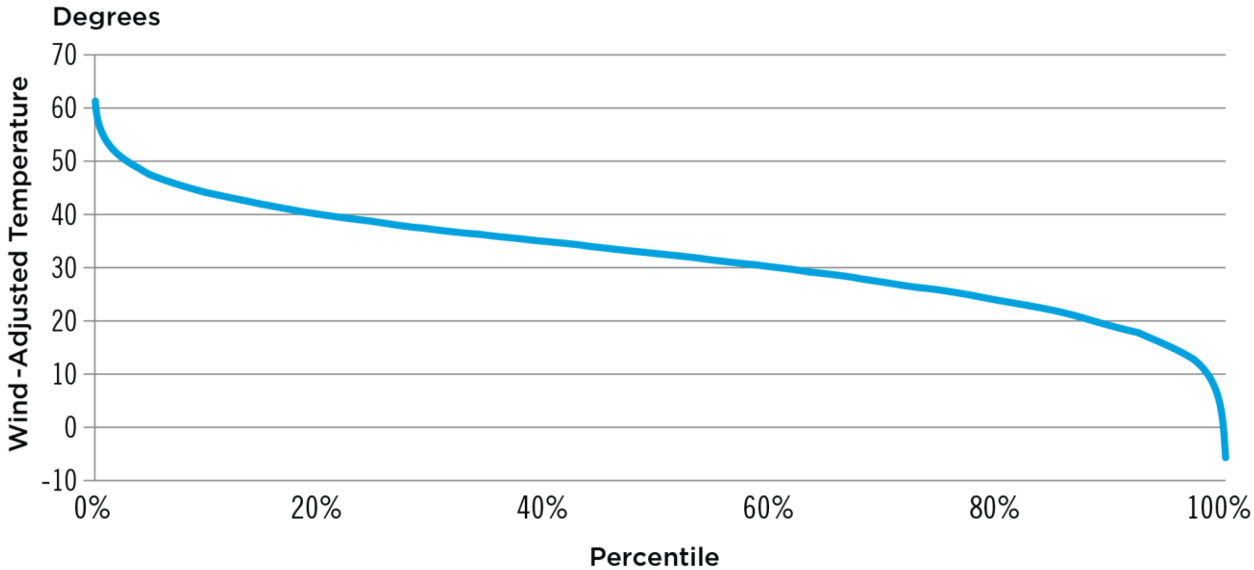
<table>
<tr><th colspan="6">Modeled Assumptions</th></tr>
<tr><th colspan="3">Study Year</th><th colspan="3">Weather Scenario</th></tr>
<tr><td colspan="3">2023/2024</td><td colspan="3">14 days</td></tr>
<tr><th colspan="6">Load</th></tr>
<tr><td colspan="2">Peak Load</td><td colspan="2">Typical: 50/50 – 1 in 2 years; (134,976 MW peak)</td><td colspan="2">Extreme: 95/5 – 1 in 20 years; (147,721 MW peak)</td></tr>
<tr><td colspan="2">Load Profile</td><td colspan="2">Typical: 2011/2012 winter</td><td colspan="2">Extreme: 2017/2018 winter</td></tr>
<tr><th colspan="6">Dispatch</th></tr>
<tr><td colspan="2">Dispatch</td><td colspan="2">Typical: Economic</td><td colspan="2">Extreme: Economic; optional maximum emergency if extreme cases present operational issues</td></tr>
<tr><th colspan="6">Retirements</th></tr>
<tr><td colspan="2">Announced: Generation retirements announced by Oct. 1, 2018, and new generation in the PJM interconnection queue and slated to be in operation by 2023</td><td colspan="2">Escalated 1: Generation retirements of 32,216 MW by 2023, with 16,788 MW of capacity added to meet the installed reserve margin requirement (15.8%)</td><td colspan="2">Escalated 2: Generation retirements of 15,618 MW by 2023 with no capacity replacement</td></tr>
<tr><td colspan="6">Escalated 1 Replacement Capacity Approach
• Replacement resources reflective of PJM interconnection queue and commercial probability
• Replacement combined cycle natural gas resources modeled as firm supply and transport
• Replacement combustion turbine natural gas resources modeled as dual-fuel with interruptible gas</td></tr>
<tr><th colspan="6">Natural Gas</th></tr>
<tr><td colspan="2">Non-Firm Gas Availability</td><td colspan="4">Typical and Extreme: 62.5% and 0%</td></tr>
<tr><td colspan="2">Pipeline Disruption</td><td colspan="2">Medium Impact: Days 1–5: 50%–100% disruption; days 6-14: 100% output (0% derate)</td><td colspan="2">High Impact: Days 1–5: 100% disruption; days 6–14: 20% derate</td></tr>
<tr><th colspan="6">Fuel Oil</th></tr>
<tr><td colspan="2">Initial Oil Inventory Level</td><td colspan="4">85%</td></tr>
<tr><td colspan="2">Oil Refueling (>100 MW site)</td><td colspan="2">Moderate: 40 trucks daily refueling rate, capped at maximum tank capacity</td><td colspan="2">Limited: 10 trucks daily refueling rate, capped at maximum tank capacity</td></tr>
<tr><td colspan="2">Oil Refueling (<100 MW site)</td><td colspan="2">Moderate: 10 trucks daily refueling rate, capped at maximum tank capacity</td><td colspan="2">Limited: 0 trucks daily refueling rate, capped at maximum tank capacity</td></tr>
<tr><th colspan="6">Expected Forced Outage Rates</th></tr>
<tr><td colspan="3">5-Year Average: Historic 5-year average, discounting gas and oil fuel supply outages</td><td colspan="3">Modeled: Regression model of expected outage rates, discounting gas and oil fuel supply outages</td></tr>
<tr><th colspan="6">Transmission Modeling</th></tr>
<tr><td colspan="3">Announced Retirements: Transmission constraints that are greater than or equal to 230 kV</td><td colspan="3">Escalated Retirements: Individual transmission constraints were not modeled; transfers into eastern PJM were limited based on CETO with a 15% transfer margin adder</td></tr>
<tr><td colspan="2">Scheduled Interchange</td><td colspan="4">Total interchange with neighboring systems limited to +/-2,700 MW</td></tr>
<tr><td colspan="2">Demand Response</td><td colspan="4">7,092 MW modeled locationally based on MW cleared by zone and nodal modeling</td></tr>
<tr><td colspan="2">Renewable Modeling</td><td colspan="4">2017/2018 cold snap profile</td></tr>
<tr><td colspan="2">Distributed Energy Resources and Energy Efficiency</td><td colspan="4">Explicitly accounted for in the load forecast</td></tr>
<tr><td colspan="2">Fuel Prices</td><td colspan="4">2023/2024 futures prices adjusted by day-to-day fluctuations in price (volatility)</td></tr>
</table>

Weather and Load

Duration of Cold Weather Event

A cold weather event is defined as consecutive days below a specified temperature threshold. To establish an appropriate duration of a cold weather event for this analysis, PJM examined weather data[4] for the current PJM footprint from 1973[5] through the 2017/2018 winter. PJM defined the temperature threshold as a wind-adjusted temperature of 20 degrees. This threshold was selected as it represents approximately the 90th percentile of winter weather experienced in PJM over the last 45 years (Figure 1).

Figure 1 Daily Winter Weather 1973–2018



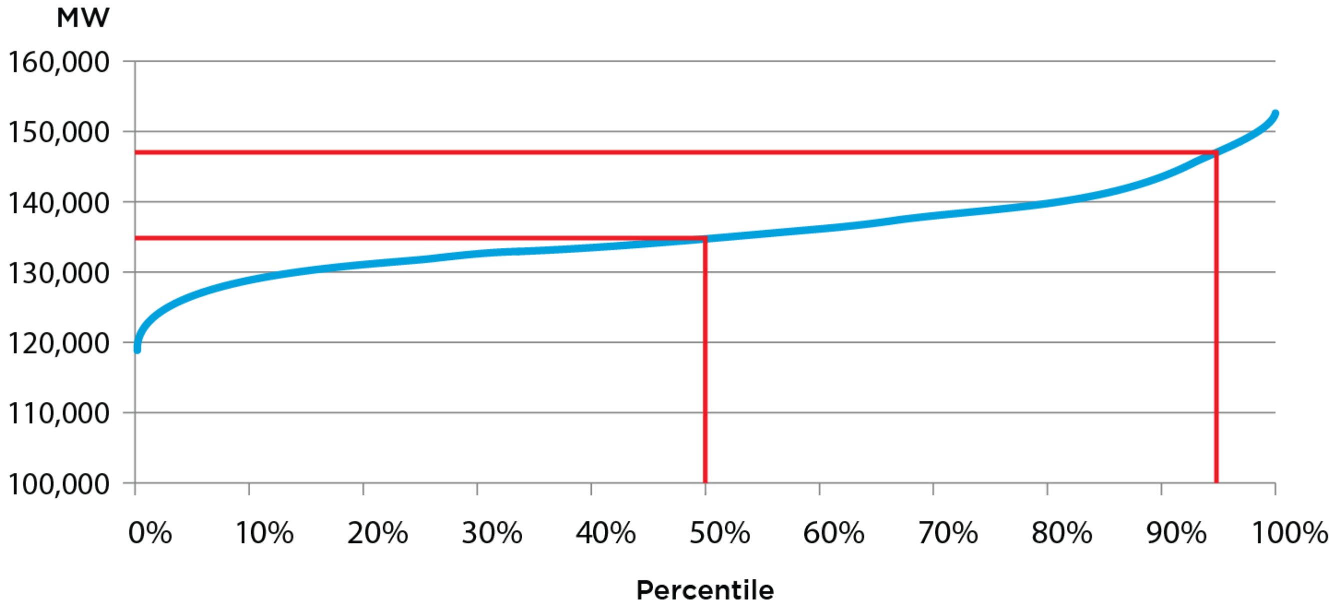
Based on this criterion, the longest-duration cold weather event in the PJM footprint over the last 45 years lasted 14 days, from Dec. 14 to Dec. 27, 1989. The second and third longest cold weather events were 12 days and 10 days in the winters of 2017/2018 and 1981/1982, respectively. While the Polar Vortex events of January 2014 and February 2015 were very cold, they only lasted three days and eight days, respectively. Assessing these historical extremes, PJM selected 14 days as the cold weather event duration (witnessed in 1989) to examine in this study.

Typical Winter (50/50 – Occurs One out of Two Years)

PJM's seasonal load model consists of two elements: the peak load of the entire season and an hourly load shape that is applied to that seasonal peak. The PJM load forecast model was used to determine the seasonal peak. The forecast model produces a distribution of seasonal peaks using historical weather simulations (Figure 2). The weather simulation period used for this study is 1973–2018. A peak load forecast is produced for each weather scenario and the resulting forecasts are then stacked from lowest to highest. The normal, or 50th percentile, peak load is then selected from this figure. As indicated in Figure 2, the 50/50 winter peak forecasted for 2023/2024 is 134,976 MW.

[4] PJM weather data is a load-weighted average of weather observations from 30+ weather stations across the RTO footprint. Zonal weather is defined in PJM Manual 19: Load Forecasting and Analysis.
[5] PJM does not have data prior to 1973.

Figure 2 Winter 2023/2024 Forecast Distribution



Hourly Load Shape

The next step in creating the seasonal load model is to establish a normal or "typical" PJM hourly load shape for that season. This typical hourly load shape will guide the selection of a historical year that is most representative of normal winter conditions.

To produce the typical shape, hourly load data is expressed as a fraction of the seasonal peak and grouped according to weekly energy use (i.e., historical weeks with the highest amount of energy use are grouped together, those with the second-highest amount of energy are grouped). This results in 14 groupings of weeks across the three-month winter period. Within each grouping, the week with the median energy is selected. The final 14 median weeks are then arranged on a calendar basis according to historical patterns. This results in a "typical" winter hourly load shape.

Note that this typical hourly load shape was derived considering only total PJM system loads and by summing non-coincident zonal peak loads, therefore, it does not reflect load diversity between PJM zones. (Load diversity refers to the fact that zones can peak at different times.) To address this diversity issue, each historical winter season is compared to the typical load shape.

A typical historical winter season is selected based on the criteria that it minimizes deviation from the typical hourly winter load shape (described above). This deviation is measured on both a calendar basis (see Figure 3) and a magnitude-ordered basis (see Figure 4). The 2011/2012 winter season, depicted in blue in the two figures below, performs best by these criteria. The blue curves clearly fall in the middle of the 11 curves in each of these two figures. The 2011/2012 winter is the load shape applied to the 50/50 RTO peak forecast of 134,976 MW to determine the hourly RTO and zonal load profiles for the typical winter case. The RTO hourly profile, with the 14-day cold snap shaded in light blue, is depicted in Figure 5.

Figure 3 Typical Winter Shape vs. Last 11 Winters – Calendar Basis

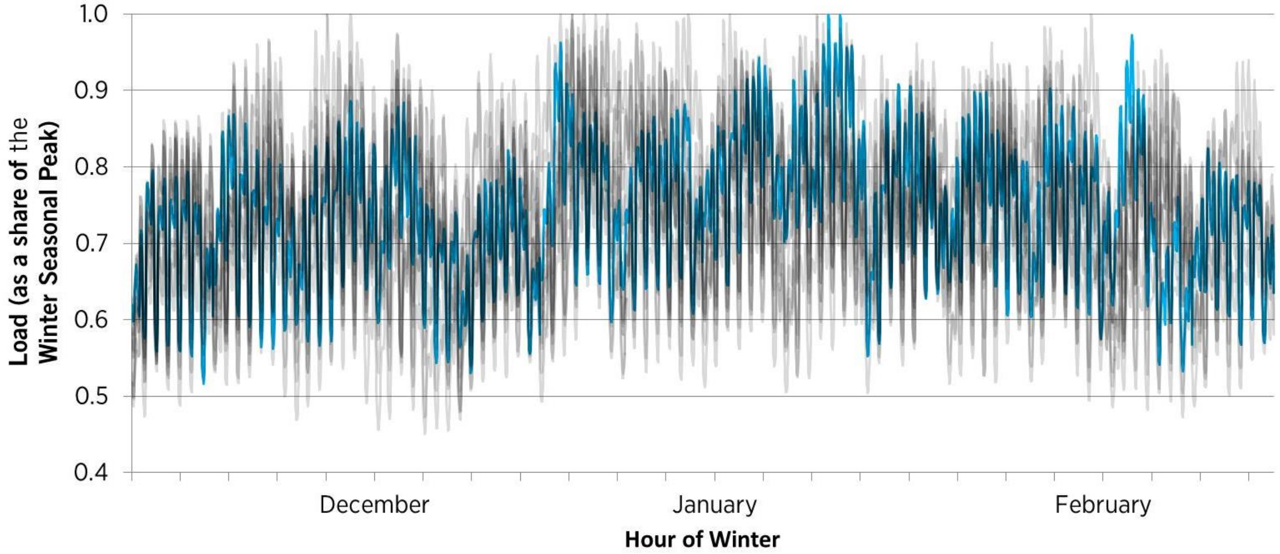


Figure 4 Typical Winter Shape vs. Last 11 Winters – Magnitude Order Basis

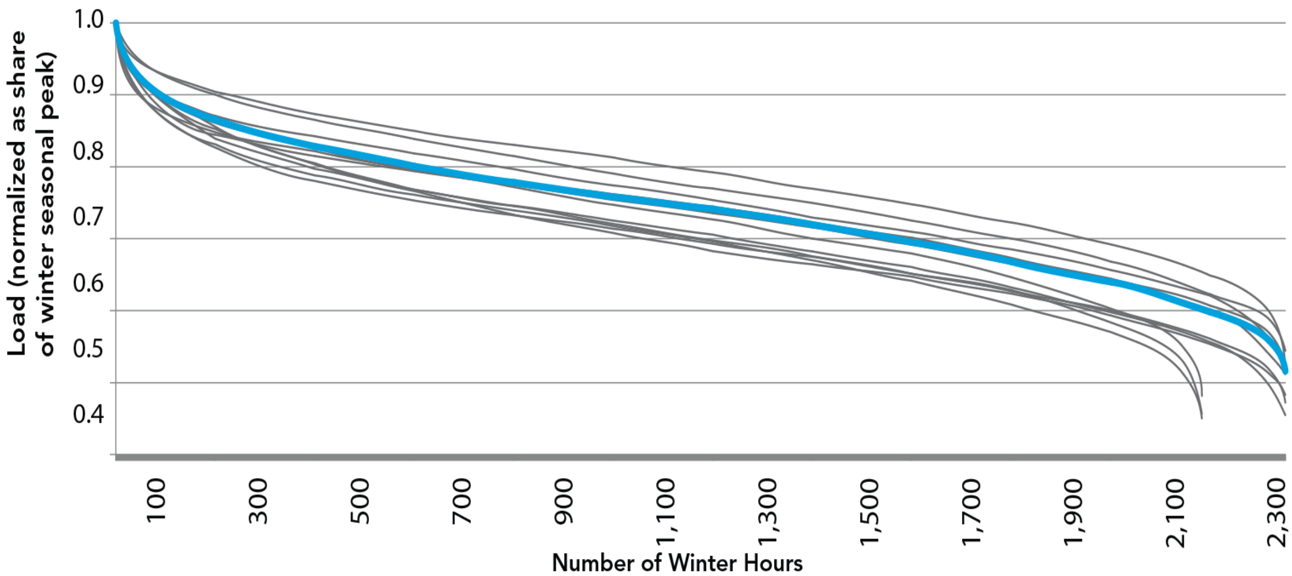
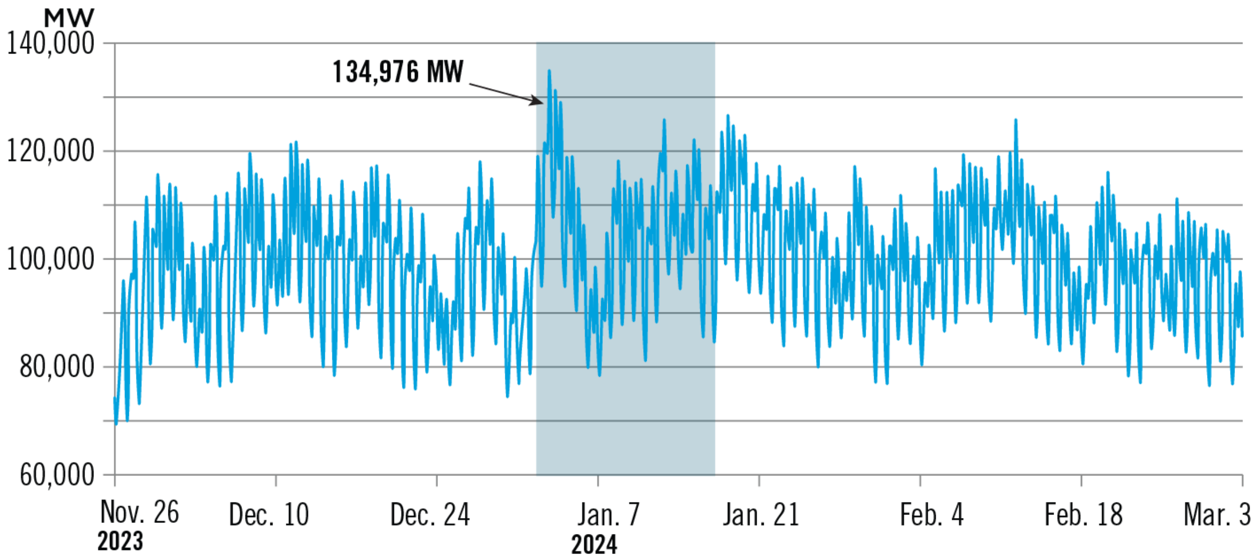


Figure 5 Typical Winter Shape Hourly Profile



Extreme Winter (95/5 – Occurs Every 20 years)

As with the typical winter, construction of the extreme winter requires a seasonal peak load and an hourly load shape that is applied to that seasonal peak. In this case, the extreme winter peak is the 95/5 peak forecast for winter 2023/2024 (147,721 MW) from the load forecast distribution (see Figure 2). By definition, a 95/5 load or greater is expected to occur, on average, once every 20 years.

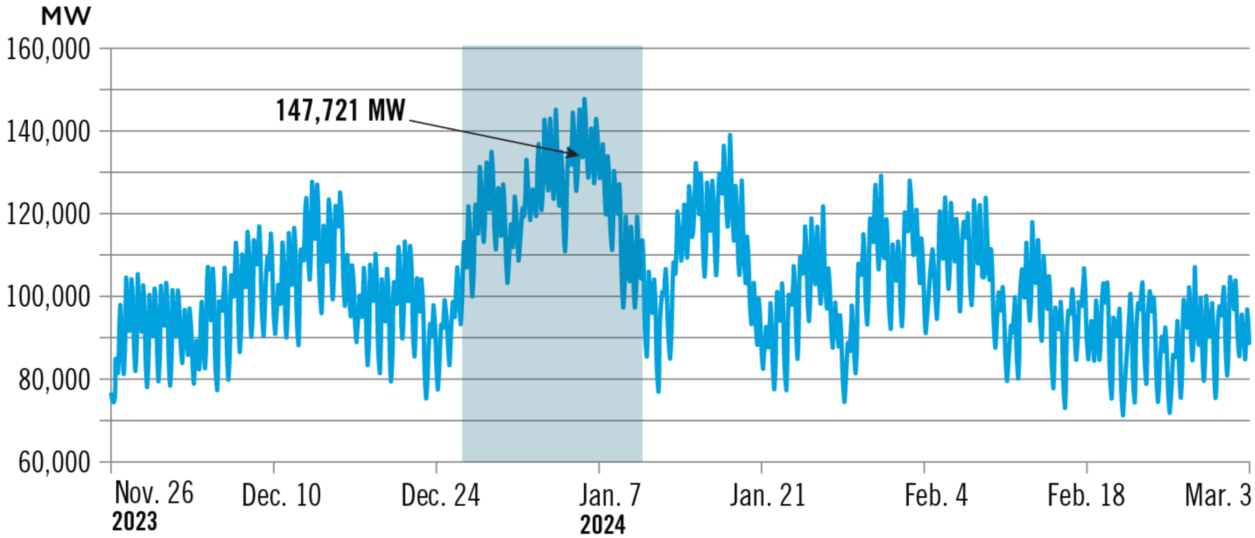
Hourly Load Profile

The next step is to establish an extreme winter hourly load profile. Extreme winters occurring simultaneously with prolonged cold weather events are uncommon by definition. Therefore, the cold snap duration analysis discussed above was used as a guide for selecting an appropriate seasonal hourly load shape.

The only 14-day cold snap experienced in the last 45 years in PJM occurred in the 1989/1990 winter season. The winter hourly load profile from 1989/1990, however, is not a candidate for use in this study because load data is unavailable for many PJM zones prior to 1998. (It would also not be prudent to use hourly load profiles that are nearly 30 years old.)

The cold weather event in 2017/2018, at 12 days' duration, is the second-longest cold snap in the last 45 years. This event is much more recent than 1989/1990 and, therefore, is much more likely to be representative of the expected PJM hourly load profile in 2023/2024. For these reasons, the 2017/2018 winter season is the load shape applied to the 95/5 RTO peak forecast of 147,721 MW to determine the hourly RTO and zonal load profiles for the extreme winter case. The RTO hourly profile, with the 14-day cold snap shaded in light blue, is depicted in Figure 6.

Figure 6 Extreme Winter Shape Hourly Profile



Natural Gas

Reliability and Disruptions

In general, the interstate pipelines have experienced very few major line failures over the last several decades. The frequency and severity of disruptions have not created any major detrimental loss of natural gas supply to PJM generation, in part because the majority of events have occurred during the time of year when demand on the natural gas system is low.

Despite the history of good performance, PJM must be prepared for a disruption during peak demand. For purposes of the PJM fuel security study, medium- and high-impact disruptions were modeled to occur during a cold temperature, high-demand period.

Study of Gas Pipeline Infrastructure

The PJM region includes shale gas resources in the prolific Marcellus and Utica plays. Based on PJM's experience, the economic availability of natural gas has led to a decline in wholesale electricity costs and an increasing dependence on this resource and associated infrastructure for meeting the electrical power needs of the PJM region.

As such, PJM has a history of evaluating the electric/natural gas interface, completing in-depth analyses in 2003, 2005 and 2015. The 2003 multi-region gas study evaluated the natural gas infrastructure adequacy over 2003–2008 in Ontario, New York, New England and PJM. The 2005 study evaluated the resilience of the natural gas infrastructure in response to postulated disruptions in pipeline and storage deliverability in PJM during the winters of 2006–2008. Following Hurricanes Katrina and Rita along the Gulf Coast, PJM commissioned a study to determine the impact of hurricanes on natural gas supply availability and prices in PJM for the 2006 winter. The 2003 and 2005 studies reflected the dependency on Gulf Coast natural gas production, and long-haul transport over a few interstate pipelines to the PJM region.

The 2015 Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric System Interface Study[6] represented a first-of-its-kind comprehensive analysis. That study looked at the gas infrastructure's capability to serve the future needs of electric generation over a region that encompasses over 1.7 million square miles, 35 states and the province of Ontario, and, at the time, served roughly 165 million people in the U.S. and Canada.

The study contained four separate analyses:

1. A baseline of the existing gas and electric infrastructure
2. An analysis of the capability of the gas infrastructure to meet the needs of the electric system over five- and 10-year time horizons
3. An analysis of electric and gas contingencies specific to each participating planning coordinator
4. A comparison of dual-fuel capability versus firm pipeline transportation for gas-fired generators to achieve fuel assurance for electric reliability

Reflecting the significant geographic change in natural gas production, the study found:

> "There exists a level of infrastructure resiliency or "robustness" that is embedded in the consolidated network of pipeline and storage infrastructure following a postulated contingency; however, gas generators may not be able to benefit due to the present priority of service paradigm and the binary firm/non-firm view of transportation service to generators."[7]

Although there is a level of infrastructure resilience within the gas pipeline system, there is no common planning standard similar to what is required for the planning of the bulk electric system. As a result, looped gas pipeline systems have a higher level of resilience than those that are not looped.

Pipeline Expansions

The 2015 study reflected the technological breakthroughs in horizontal drilling that enabled the economic recovery of natural gas from shale formations, which in turn, shifted natural gas production from the Gulf Coast region to the PJM region and other shale regions in a matter of years. This shift in production has switched the flow of gas from importing into the PJM region to exporting from the PJM region. The EIPC Gas-Electric System Interface Study detailed the existing pipeline infrastructure as of the end of 2013.[8]

Since the beginning of 2014, a few months after the EIPC study was started, a total of 26.2 billion cubic feet per day (bcfd) of pipeline capacity has been added in the PJM region. Another 22.8 bcfd of pipeline capacity is under various stages of proposal/approval/construction and expected to be online by the end of 2021.[9] To put these numbers in perspective, the U.S. produces roughly 55 bcfd of shale gas, with 25 bcfd coming from Appalachia (Marcellus and Utica gas plays). See Figure 7. PJM generation currently consumes approximately 3.5 bcfd.

[6] http://www.eipconline.com/Gas-Electric.html.
[7] Ibid.
[8] EIPC Gas-Electric System Interface Study, Target 1 report: http://nebula.wsimg.com/d28ed8902535b1f517d7a826c79f44421?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1 and Appendix 1: http://nebula.wsimg.com/8d96dc6b1652a22b3e5766ada95908ae?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.
[9] Derived from IHS Markit U.S. and Canadian Pipeline Expansion Database: July 2018 update.

Pipeline Interconnections

Due to the geologic and geographic location of the PJM region, the resulting pipeline infrastructure is well interconnected and diversified. The prolific production areas, multitude of storage sites, gas hubs and consumers are connected by a vast network of interstate, intrastate and local pipelines. The benefits of this growing interconnectivity were reflected in the 2005 gas study, which found that, "The network of storage fields and pipelines operated by these pipelines [Dominion, Columbia, Equitrans and National Fuel Gas] provides significant operational linkages, flexibility and adaptability for responding to operating contingencies."

Subsequently, the 2015 study, which analyzed postulated gas system contingencies in PJM, found, "Gas sector infrastructure improvements have resulted in much greater operational flexibility across the pipelines and storage infrastructure that heighten the resiliency of the network to compensate for brief intervals when highly disruptive gas-side contingencies are tested."

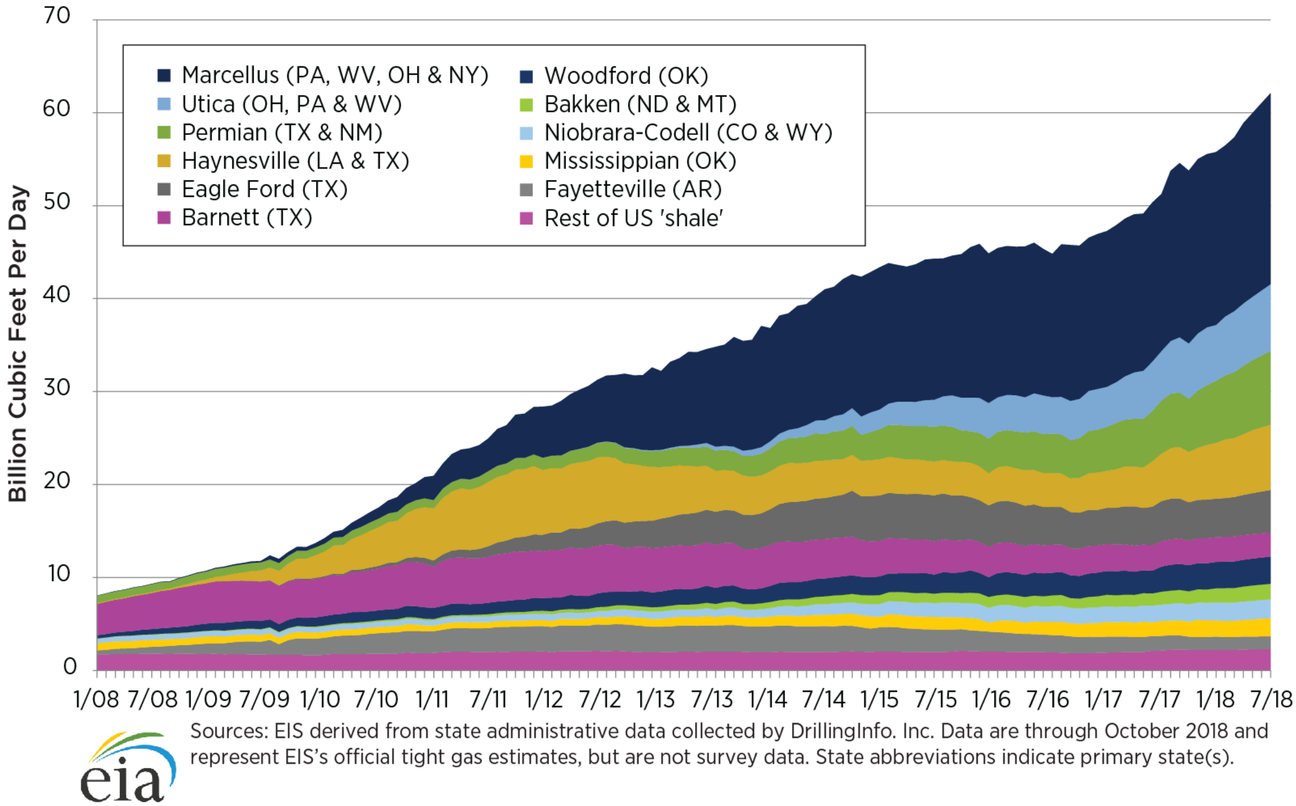
The interconnection of pipelines strengthens mitigation strategies such as utilizing line pack, spare capacity of compressor stations and reversing flow across pipeline segments.

Natural Gas Production Growth

Since 2017, natural gas production has seen the largest incremental growth in U.S. history, increasing by more than 10 bcfd, with the Marcellus/Utica (Appalachian) region accounting for over half of that.[10] As such, in spite of the significant increase in pipeline expansion mentioned above, there is an oversupply of natural gas in the marketplace.[11]

[10] IHS Markit Global Gas Insight: U.S. natural gas: Safe bet on supply? August 8, 2018.
[11] IHS Markit Houston Energy Briefing. October 2018.

Figure 7 Monthly Dry Shale Gas Production



Sources: EIS derived from state administrative data collected by DrillingInfo. Inc. Data are through October 2018 and represent EIS's official tight gas estimates, but are not survey data. State abbreviations indicate primary state(s).

Natural Gas Storage in PJM

Across the U.S., natural gas is stored mainly in depleted oil/gas reservoirs, with the remainder in aquifers or salt caverns.[12] The type of storage affects how the storage can be used. Natural gas in storage caverns can be cycled multiple times per year, while depleted reservoirs and aquifers can only be cycled seasonally, injected during the non-heating season and withdrawn during the heating season.

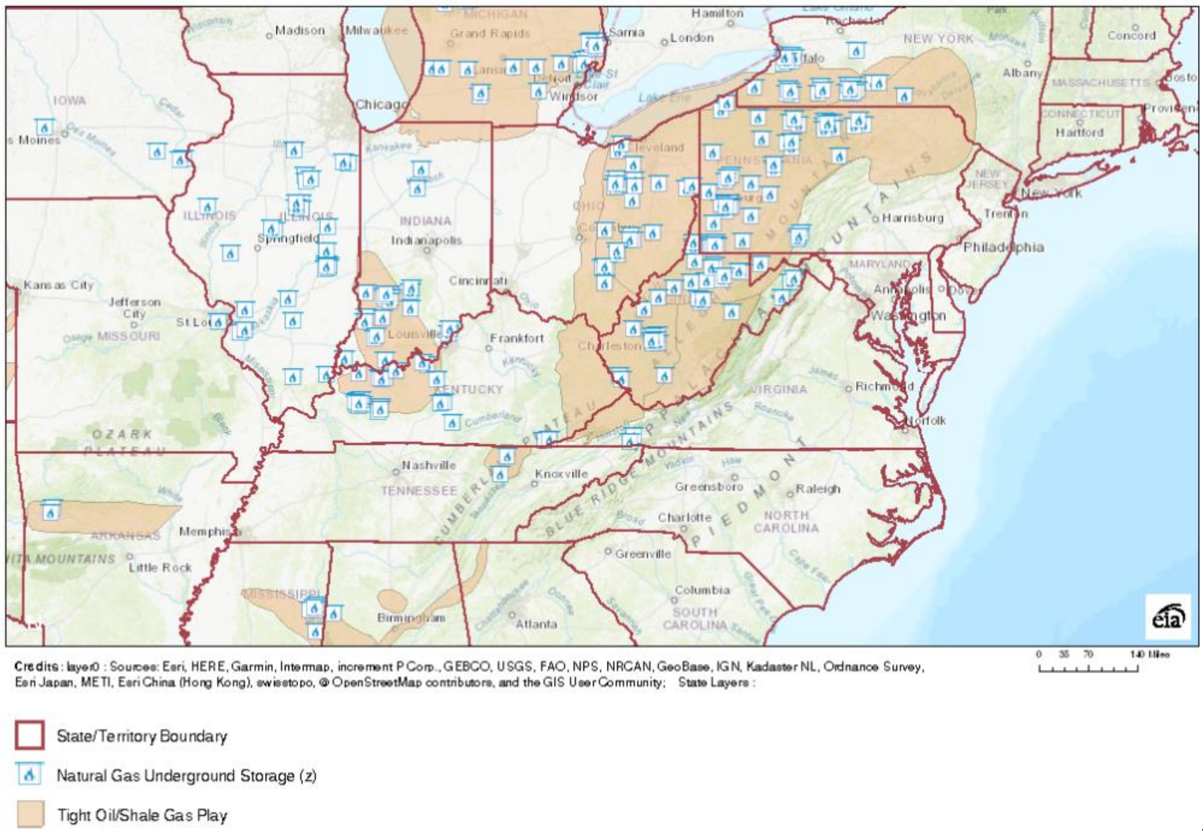
This storage infrastructure was put in place during the years when natural gas was mainly produced in the Gulf Coast region. Its primary purpose is to handle seasonal gas demand and pricing fluctuations. The majority of storage infrastructure is used by local gas distribution companies that serve residential and commercial gas users – the customers who historically are most reliant on winter supply reliability (Figure 8).

While most natural gas-fired generators do not hold storage capacity contracts, the flexibility afforded by storage in terms of the ability to store excess gas and withdraw needed supply are key physical characteristics that can greatly assist with their unique operating requirements. At a 2018 natural gas conference, a representative from the gas industry noted the need for enhanced services and storage, saying: "Natural gas deliverability is the ability to deliver gas at the required location, time,

[12] Jurisdictional Storage Fields in the United States by Owner (Updated May 23, 2013), http://www.ferc.gov/industries/gas/indus-act/storage/fields-by-owner.pdf

pressure and quantity …. The higher deliverability requires more capacity reservation, more known notice, more hourly service and more reliance on line pack and market-area storage."[13]

Figure 8 Natural Gas Storage Infrastructure in the PJM Region



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Natural Gas Transportation

Natural gas is shipped on pipelines based on contracts for transportation. Firm transportation guarantees delivery under all circumstances, except *force majeure*. Non-firm, or interruptible transportation, is a lower-priority service that depends on the availability of pipeline capacity and may be interrupted should conditions warrant. As mentioned earlier, pipelines are developed and designed based only on the amount of firm transportation contracted by shippers. The pipeline infrastructure is not designed to include a reserve margin to mitigate the impact of *force majeure* events.

Natural gas-fired generators typically acquire needed natural gas through third-party fuel suppliers, as opposed to directly contracting for firm transportation. This allows the generator to "firm up" gas supplies when needed. Even so, PJM has seen an increase in the use of firm transportation contracts since the inception of its Capacity Performance product in 2015.

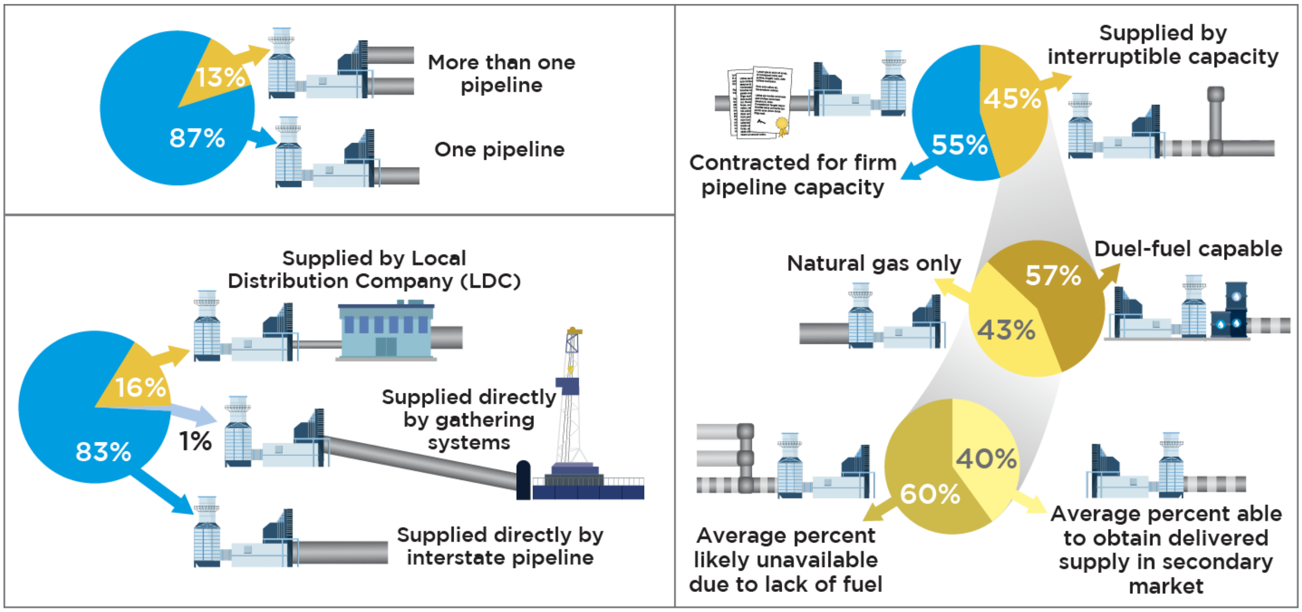
[13] *Pipelines need to offer flexible gas deliveries as renewables' role grows*, S&P Global Market Intelligence October 10, 2018
[14] https://www.eia.gov/state/maps.php?v=Natural%20Gas

Natural Gas Generator Fuel Delivery Characteristics

Taking into account the existing and planned generation in the interconnection queue with interconnection service agreements and known gas delivery characteristics, there are 462 natural gas-fired generating units totaling approximately 87,000 MW, ranging from smaller combustion turbines, primarily used for peak load periods of the day, to larger and more efficient combined-cycle units that provide more traditional base-load generation. Around 83 percent of the total gas generation capacity receives its natural gas supply directly from an interstate pipeline. Approximately 16 percent is located within Local Distribution Companies (LDC) or "behind the city gates" of local natural gas distribution companies, and the remaining 1 percent obtain supply directly from producers' natural gas-gathering systems.

Roughly 55 percent of the total natural gas-fired capacity in PJM contracts directly for firm pipeline capacity, with the remaining portion utilizing the pipeline's ability to supply interruptible capacity that is available during the majority of the non-winter months of the year. Of the total non-firm capacity, approximately 57 percent has dual-fuel capability. Of the balance of non-firm generation, PJM has observed that around 40 percent is active in the secondary gas market and able to obtain delivered supplies when needed to meet their obligations. Finally, around 13 percent of all gas-fired generators have the ability to receive gas from more than one interstate pipeline.

Figure 9 Natural Gas Generator Fuel Delivery Characteristics



Natural Gas Disruption Assumptions Modeled in Study

In order to effectively stress natural gas-fired generator performance during the 14-day study period, PJM introduced a set of four independent interstate pipeline disruption events. The locations were selected for each of these disruptions based on several characteristics that were important to the study. These characteristics include generation facility clusters, levels of generating capacity within those clusters, PJM's overall reliance on a particular pipeline as well as the configuration and design of the pipeline segment feeding these generation resources.

Given the number of pipelines that exist across the PJM system, many more pipeline disruption scenarios could have been postulated and analyzed, but for the purposes of this study, the four selected scenarios provided balanced examples of various types of impacts to fuel supply. In each of these cases, PJM did not disrupt the entire pipeline, but focused on the more credible impacts to the generators downstream of the disruption that would realistically be impaired by the event. Additionally, PJM reviewed these disruption scenarios with each of the interstate pipelines to assess the viability of both the disruption scenarios and the potential downstream impacts.

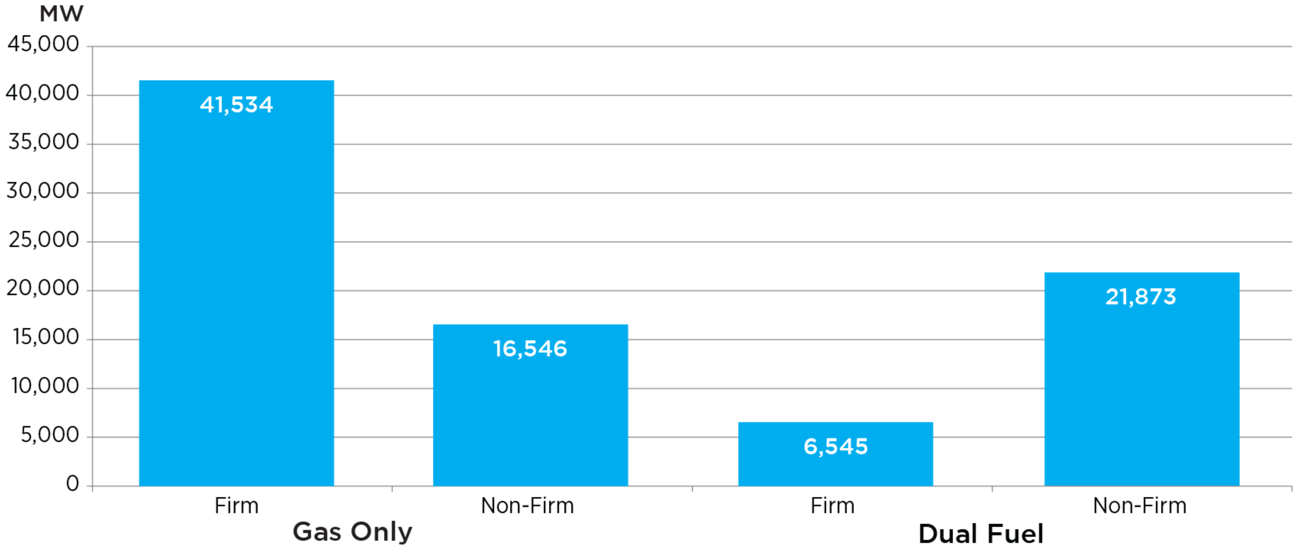
A key assumption of each disruption scenario is the length of the disruption and the effective impact on gas delivery to downstream generators. In reviewing historical data of actual pipeline failures, the list of events is quite small and even smaller during the winter season. One such event occurred in PJM in December 2017, in which the impacted pipeline was restored to service in approximately 3.5 days. While there have been instances of pipelines being derated for longer periods, those have been primarily during the non-winter months when the full capacity of the pipeline is not required and further inspections may have been needed prior to returning it to service.

It is PJM's view that all efforts will be put into returning a pipeline to service as quickly as possible during a winter high gas-demand period to ensure that human needs of customers are not jeopardized by the lack of heat. After further consultation with INGAA and various pipelines, PJM settled on a five-day pipeline disruption duration beginning on day one of the 14-day study period.

Natural Gas Availability Modeled in Study

Another key set of assumptions is generator fuel delivery attributes. These attributes include type of interstate pipeline transportation contracts (firm or non-firm), single or multiple pipeline supply connections and dual-fuel capability. To determine these generator fuel attributes, PJM relied primarily on its annual generator fuel survey for which all generators are asked to provide updated information related to fuel supply and capabilities. For this study, the baseline breakdown of gas supply attributes is shown in Figure 10.

Figure 10 Gas Supply Attributes Used in Fuel Security Study



PJM performed two sensitivities for units that are gas-only with only non-firm gas transportation: one with 0 percent of non-firm gas generating capacity and the other with 62.5 percent of non-firm generating capacity available. These sensitivities are based on analysis of historic Generator Availability Data System (GADS) data, which indicated that 62.5 percent of these generators, on average, were able to obtain delivered gas supply in the secondary market.

As PJM analyzed each of the disruption scenarios, these attributes were also taken into account to determine the net downstream impacts and resultant loss or unavailability of generation. For purposes of this analysis, all generating units with firm transportation were assumed to be available under all temperature conditions and only impacted within a pipeline disruption scenario. All dual-fuel units were assumed to be operating on backup fuel during a pipeline disruption.

Retirements and Replacements

Because the fuel security study time frame is the 2023/2024 winter, PJM took into account the quantity and type of generation that was replacing retiring generation assets. Under the various retirement scenarios (announced, escalated 1 and escalated 2), the vast majority of new generation is projected to be natural gas.

To determine the fuel attributes of this incremental generation, PJM relied upon data currently available from the generation developers. For the balance of incremental gas-fired generation, PJM based the fuel attributes on recent trends that have been observed for each technology type. For combined cycle units, which represent approximately 95 percent of new gas-fired generation, PJM assumed that 100 percent of these megawatts were operating with firm pipeline transportation capacity. For the smaller combustion turbines, representing approximately 5 percent of new gas-fired generation, the assumption was made that each of these units would have dual-fuel capability. The incremental generation that is projected to be sited within any of the four postulated pipeline disruptions was added into the analysis as shown in Figure 11 below.

Figure 11 Incremental Generation Projected to Be Sited Within Modeled Pipeline Disruptions

Pipeline Disruption	Gas-Only Generation (MW)			Dual-Fuel Generation (MW)			Total (MW)
	Non-Firm	Firm	Total	Non-Firm	Firm	Total	
Looped 1	2,690	3,094	**5,784**	7,828	103	**7,931**	**13,715**
Looped 2		3,015	4,483	2,720	1,380	4,100	8,583
Replacement Generation (Escalated 1 Portfolio)		+ 435	+ 435	+ 225			+ 660
	1,468	3,450	**4,918**	1,468	3,450	**4,325**	**9,243**
Single 1		1,821	3,004	470	803		4,277
Replacement Generation (Escalated 1 Portfolio)		+ 774	+ 774		+ 774		+ 774
	1,183	2,595	**3,778**	1,183	2,595	**1,273**	**5,051**
Single 2	330	750	**1,080**	1,872	1,769	**3,641**	**4,721**

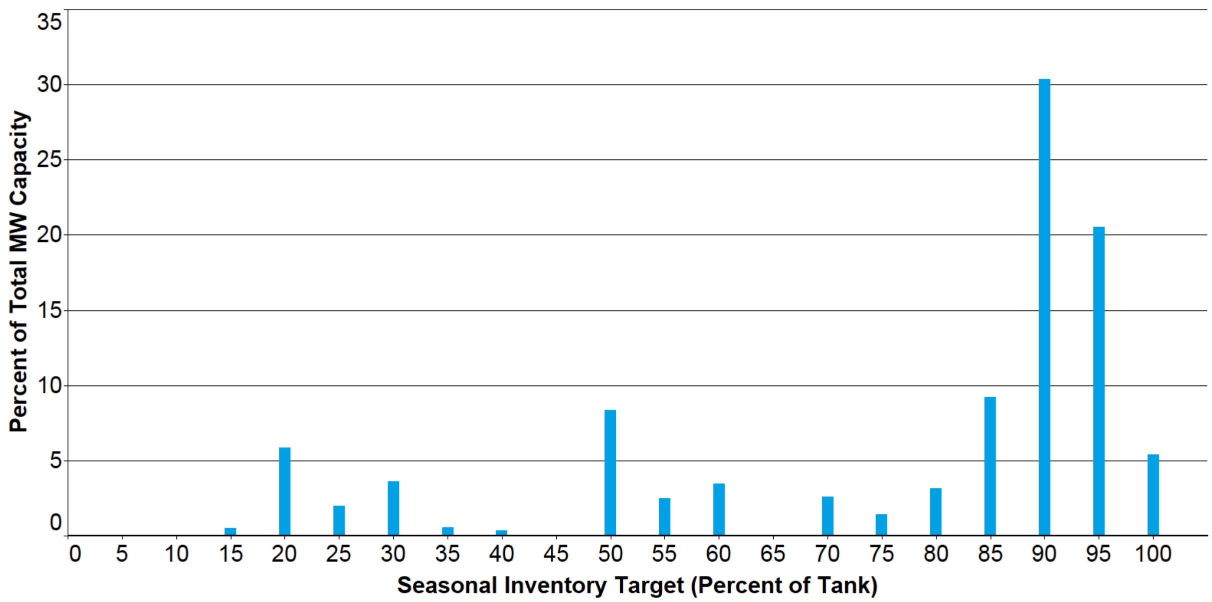
On-Site Fuel Inventories

Oil Inventory Data

Oil tank capacities vary from site to site within the PJM footprint. PJM collects data about these capabilities through eDART surveys and performed an evaluation of the most current responses as well as past responses to develop a total storage capacity for each oil unit. Survey data was also used to identify which oil tanks are dedicated to a single generator and which oil tanks are connected to multiple generators.

The inventory capacities, which were developed in terms of generator run hours, were converted to BTU capacities by using the heat rates of the associated units. These inventory-to-generator relationships and the BTU capacity of the inventories were then used in the Phase 1 study simulations. The distribution of oil inventories within PJM is shown in the Figure 12. Based on asset owner feedback, the average tank size for a combustion turbine is approximately three days' worth of oil.

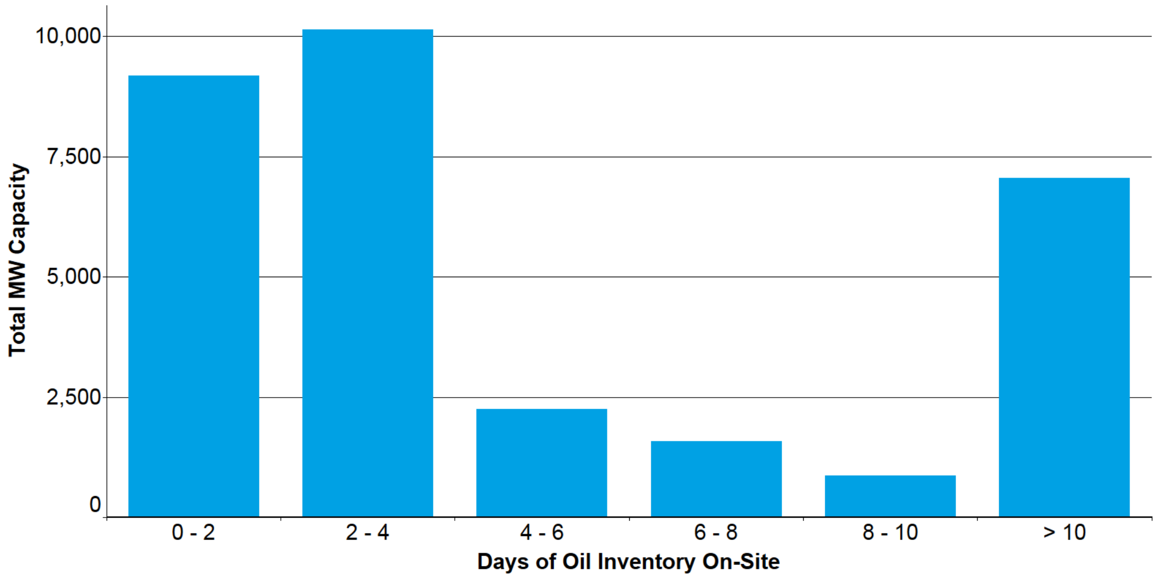
Figure 12 On-Site Oil Inventories



Starting Oil Tank Level

In order to determine the appropriate starting level to use in the study, PJM included a question in an eDART survey asking for units with on-site oil storage to provide their starting winter inventory target as a percentage of total available storage capacity. Based on the responses, the most common inventory target, by a significant margin, is 90 percent tank level (Figure 13). The median value of 85 percent tank level was used as a starting point for the study. The distribution of the responses is shown in the chart in Figure 13.

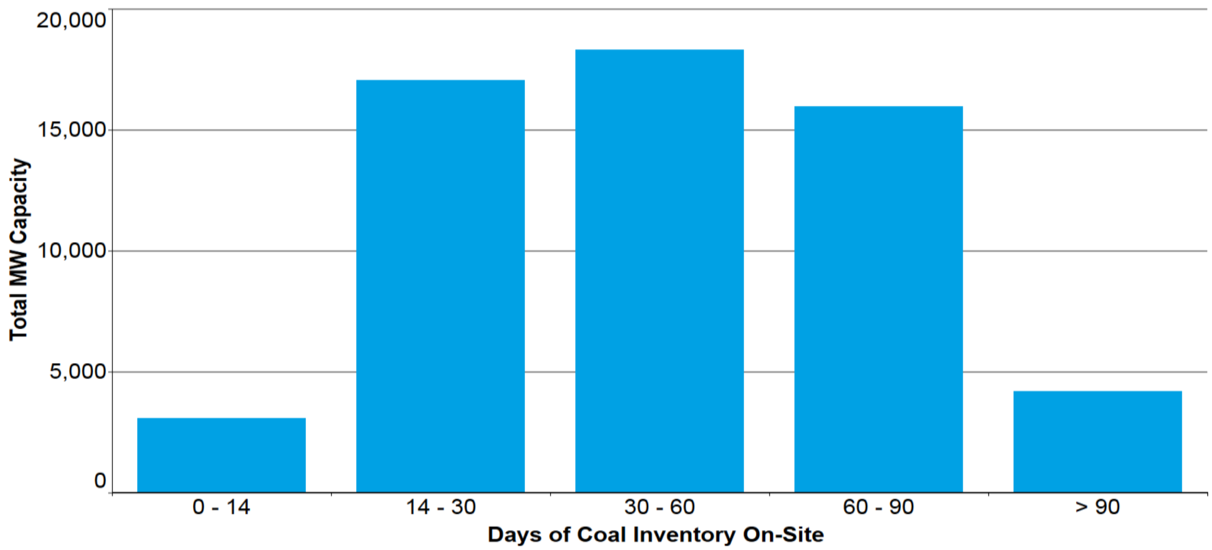
Figure 13 Winter Starting Inventory Targets for On-Site Oil



Coal Inventory Data

Coal-fired units have historically maintained a significant inventory of fuel on-site year-round, enough of an inventory that even if coal replenishments ceased for the entire 14-day period of the study the unit would remain available (Figure 14). The average on-site fuel inventory for coal is approximately 30 days. Because of this, disruptions to the coal fuel supply chain was not simulated or subjected to any stress during the Phase 1, and therefore, were out of scope for this 14-day study. A detailed analysis of the data provided by coal units to PJM via eDART surveys yielded the chart below. As shown in the data, coal units within PJM's footprint continue to maintain significant coal piles.

Figure 14 On-Site Coal Inventories



Nuclear Inventory Data

Nuclear refueling timelines are plant specific, but typically occur on an 18- or 24-month cycle, therefore, were out of scope for this 14-day study.

Forced Outages

Forced outages were applied to typical and extreme weather scenarios. Historical five-year average Equivalent Demand Forced Outage Rates data was used for typical scenarios and a regression model was developed to estimate forced outage rates for extreme scenarios.

Forced Outage Rates for Typical Weather Scenarios

Given the typical weather conditions in its 50/50 winter scenarios, PJM used unit-specific, five-year average Equivalent Demand Forced Outage Rates (EFORd). Calculation information can be found in PJM Manual 22: Generator Resource Performance Indices.[15]

Gas and oil unit unavailability due to fuel supply chain issues is explicitly modeled as part of the sensitivity analyses. Therefore, to avoid double counting in the forced outage rates, the unit-specific EFORd calculation for natural gas and oil units excluded forced outages with the "Fuel Supply" NERC GADS cause code.

PJM did not use forced outage rates for wind, solar and hydro resources, as they were modeled using hourly, unit-specific output profiles from the 2017/2018 winter season. Table 3 shows average of the unit-specific EFORd modeled in typical winter scenarios by resource type.

Table 3. Typical Winter: Resource Type-Specific Forced Outage Rates

Coal	8.45
Gas Combined Cycle*	5.68
Gas CT*	5.73
Gas Steam*	10.14
Hydro	13.06
Nuclear	1.38
Oil CT*	15.24
Oil Steam*	13.70
Biomass/Landfill Gas/Wood	10.83

*Calculations exclude forced outages with "Fuel Supply" NERC GADS cause code

Regression Model for Development of Forced Outage Rates under Extreme Weather Scenarios

To assess the resilience of the PJM system in the fuel security study, the performance of the generation fleet was examined under an extreme, extended duration weather condition. Outage rates of the fleet are expected to be influenced, at least in part, by weather conditions. To test this hypothesis and predict outage rates under the extreme and extended weather

[15] https://www.pjm.com/-/media/documents/manuals/m22.ashx.

scenario used in the highly stressed simulations, PJM developed a regression model. Regression Model Forced Outage Rates were applied to cases that used extreme winter loads.

Method

A two-way, random-effects panel regression model was employed to estimate generator outage rates under an extreme weather scenario. This study used a panel of historical daily data from the NERC Generator Availability Data System (GADS) for PJM generators[16] from Jan. 1, 2014, through Jan. 8, 2018. The data set included generators that came into service or retired over the observation period.[17]

To estimate forced outages under an extreme cold weather scenario, the model predicted daily forced outages using observed weather parameters from Jan. 1, 2014, to Dec. 27, 2017. The model was then used to extrapolate forced outages from Dec. 28, 2017, to Jan. 8, 2018, under an extreme cold weather scenario by decreasing the observed weather parameters by 20 degrees Fahrenheit and estimating the model.

The estimated forced outage rates were then used in the PLEXOS simulation for the extreme stressed portfolio assessment. Fuel supply related outages for gas and oil resources were not included in the forced outage rate provided to the simulation, as outages of this nature were captured in the pipeline contingencies included in the simulations.

The two-way, random-effects modeling technique was selected because panel models have multiple advantages over models that only capture differences in forced outage rates between generators within the PJM fleet during single year, or changes in forced outage rates of a single generator over time. Because panel models included the internal PJM generation fleet over time, variation in forced outage rates due to difference between generators and within individual generators across time was captured. This increased variation mitigates the impact of multicollinearity[18] by introducing additional variation to the model. This increased variation provides additional information to the model and enabling for more robust and efficient estimation.

Additionally, and arguably the greatest benefit of using a panel regression model, is that the modeling technique controls for omitted variable bias due to the unique characteristics of a generation plant that impact the forced outage rate. For example, consider daily operational routines that are specific to the management of a generator. It is conceivable that some managers may operate the generator closer to optimal as the result of the skill or experience of the manager. This operational style could theoretically affect the forced outage rate of the generator, assuming that sub-optimal operation of the generator would lead to higher forced outage rates. To the extent that this assumption is true, not controlling for the impact of skill/experience of management in the model results in biasing the model. Because this skill/experience effect would be nearly impossible to explicitly measure, omitted variable bias is seemingly inevitable. However, panel models control for this omitted variable bias through the inclusion of the effect of such unobserved effects in the composite error term.[19]

[16] Forced outages were not estimated for wind and solar resources and were therefore not included in the panel data set.
[17] The inclusion of generators that retire or come into service during the observation period in the data set results in an unbalanced panel. To control for bias in the random effects estimators that may be the result in the unbalanced panel, the variance components are calculated using the Wansbeek and Kapteyn method. Wansbeek, Tom and Kapteyn, Arie, (1989), Estimation of the error-components model with incomplete panels, Journal of Econometrics, 41, issue 3, p. 341-361, https://EconPapers.repec.org/RePEc:eee:econom:v:41:y:1989:i:3:p:341-361.
[18] Multicollinearity occurs when two or more independent variables are perfectly or highly collinearity. For greater discussion of multicollinearity, see Kennedy, P. (2013). A guide to econometrics (E ed., Vol. 6). Malden (Mass.): Blackwell Publishing.
[19] For further information on the composite error term see Wooldridge, J. (2003). Econometric analysis of cross section and panel data. MIT Press.

Theoretical Model

The following theoretical model was employed to estimate forced outage rates under an extreme weather scenario:

$$EFOF_{it} = \alpha_{it} + \beta_1 Age_{it} + \beta_2 Age\_Squared_{it} + \beta_3 Resource\_Type_{it} + \beta_4 Operating\_Owner_{it} + \beta_5 Zone_{it} + \beta_6 Weather_{it} + \beta_7 Cold\_Front_{it} + \beta_8 Polar\_Vortex_{it} + \beta_9 Winter_{it} + \beta_{10} Summer_{it} + \beta_{11} Last\_Start_{it} + \beta_{12} Utilization_{it} + \beta_{13} Basepoint\_Volatility_{it} + \beta_{14} Outage\_P_{it} + \beta_{15} Outage\_M_{it} + \varepsilon_{it}$$

Where:

Equivalent Forced Outage Factor (EFOF) was modeled as the dependent variable and measures unavailability of a resource due to forced outages or derating during any given period.[20] EFOF captures both full and partial forced outages, and both types of unavailability are estimated by the regression model.

$$EFOF = \frac{Forced\ Outage\ Hours + Equivalent\ Forced\ Individual\ Forced\ Derated\ Hours}{Period\ Hours} * 100$$

And:

Variable	Measurement	A Priori Theory (*Ceteris Paribus*[21])
Age & Age Squared	Year – In Service Year & Age*Age	There is a quadratic relationship between the age of a resource and its forced outage rate, where forced outages are high when first in service, stabilizes and increases as the resource ages. This effect is referred to as the “bathtub curve”
Resource Type	Type of resource + primary fuel type	Certain resource types are more prone to outage than others
Operating Owner	Operating owner	Variation in standard operating procedures that differ across operating owners may result in variation in forced outages
Zone	Transmission zone	Due to load, weather, geographical idiosyncrasies and differences in operating owners, there may be zonal differences in outages
Weather	Wind-adjusted daily average temperature for winter Humidity-adjusted daily average temperature for summer Dry-bulb temperature daily average for shoulder months Note: zonal, load weighted average	Colder weather leads to higher outages
Cold Front	Indicator if wind-adjusted daily average temperature <= 15 degrees for 3 or more days	Sustained extreme weather results in greater outages relative to shorter instances of cold weather
Polar Vortex	Indicator if day is a polar vortex day	Forced outages during the polar vortex are outliers and have above-average forced outage rates
Winter	Seasonal dummy, relative to shoulder	There is a seasonal difference in forced outage rates
Summer	Seasonal dummy, relative to shoulder	There is a seasonal difference in forced outage rates

[20] EFOF differs from the equivalent demand forced outage rate (EFORd) in that EFORd measures forced outages that occur during that peak demand period.

[21] *Ceteris Paribus* – with other conditions remaining the same.

Variable	Measurement	A Priori Theory (*Ceteris Paribus*[21])
Last Start	Days since last start	The greater the days since last start, the greater the forced outage rate when called upon to start
Planned Outage	# of days since last planned outage	Unclear direction of the a priori; however, planned outages are assumed to be indicative of maintenance practices, and therefore theoretically relevant
Maintenance Outage	# of days since last maintenance outage	Unclear direction of the a priori; however, maintenance outages are assumed to be indicative of maintenance practices, and therefore theoretically relevant
Basepoint Volatility	$\dfrac{\left(\frac{\sum (\text{SE MW}_t - \text{SE MW}_{t-1})^2}{\text{ICAP}}\right)_{day}}{\left(\frac{\sum (\text{SE MW}_t - \text{SE MW}_{t-1})^2}{\text{ICAP}}\right)_{week}}$	Basepoint volatility that exceeds normal wear and tear on a resource leads to greater forced outages
Utilization	$\dfrac{\left(\frac{\sum \text{SE MW/ICAP}}{\text{\# Intervals ran}}\right)_{day}}{\left(\frac{\sum \text{SE MW/ICAP}}{\text{\# Intervals ran}}\right)_{month}}$	Utilization that exceeds normal wear and tear on a resource leads to greater forced outages.

Although not included as part of the theoretical model, an indicator variable that controls for the impact of outliers (outside of the Polar Vortex) as identified by the interquartile range test was included as part of the model validation and subsequent estimation process.

Results

In general, the results confirmed the a priori theory with high statistical significance. Despite being statistically significant, the magnitude impacts of several effects were unexpectedly low, and in some cases, indistinguishable from zero. The effect with the largest impact, outlier, is evidence that further investigation into the specification of this model is warranted. However, the sampling accuracy of this model is highly accurate and overall the model performs well.

0 displays the regression results used to estimate forced outage rates under an extreme weather scenario.

Table 4. Regression Results

	Estimate	*P-value*
Intercept	0.0039	*<0.0001*
Age	0.0017	*<0.0001*
Age Squared	<0.0001	*<0.0001*
Weather	-0.0001	*<0.0001*
Cold Front	0.0036	*<0.0001*
Polar Vortex	0.0230	*<0.0001*
Winter	-0.0019	*<0.0001*
Summer	0.0031	*<0.0001*
Last Start	<0.001	*0.0072*
Outage P	<0.001	*0.0003*
Outage M	<0.0001	*<0.0001*
Basepoint/Volatility	0.0005	*<0.0001*

Model Description & Fit Statistics	
N	1,611,289
MSE	0.0055
R-Square	0.8559
DFE	1,611,275
Root MSE	0.0738

	Estimate	*P-value*
Utilization	-0.0001	*<0.0001*
Outlier	0.8150	*<0.0001*

On average, the model accurately estimated EFOF within 1 percentage point. Figure 15 displays the average monthly RTO error. During prolonged weather events, the model tends to underestimate toward the end of the cold snap. This may be due to using zonal load-weighted temperatures. Future uses of this model may benefit from using non-load weighted, more location-specific weather data. Figure 16 demonstrates the model error during the 2017/2018 cold snap.

Figure 15 Average Monthly RTO-Wide Error During Observation Period

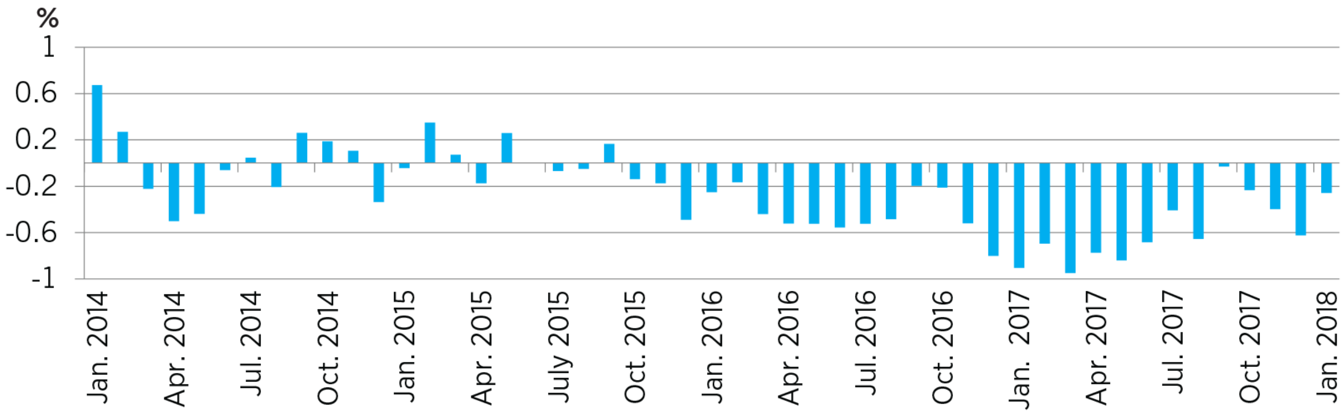


Figure 16 Model Error During 2017/2018 Cold Snap

To estimate forced outages under an extreme cold weather scenario, the model estimated daily forced outages using observed weather parameters from Jan. 1, 2014 to Dec. 27, 2017. The model was then used to answer the question "what would forced outages have been during the 2017/2018 cold snap if, holding all else constant, the weather was more extreme?" by extrapolating forced outages from Dec. 28, 2017 to Jan. 8, 2018 using extreme cold temperatures. Figure 17 displays estimated forced outage rate under the extreme weather scenario, versus what was observed in the RTO over that period.[22] Table 5 shows average unit-specific outage rate modeled in extreme winter scenarios by resource type.

Figure 17 Estimated Forced Outages Rates vs. Actual Forced Outage Rates

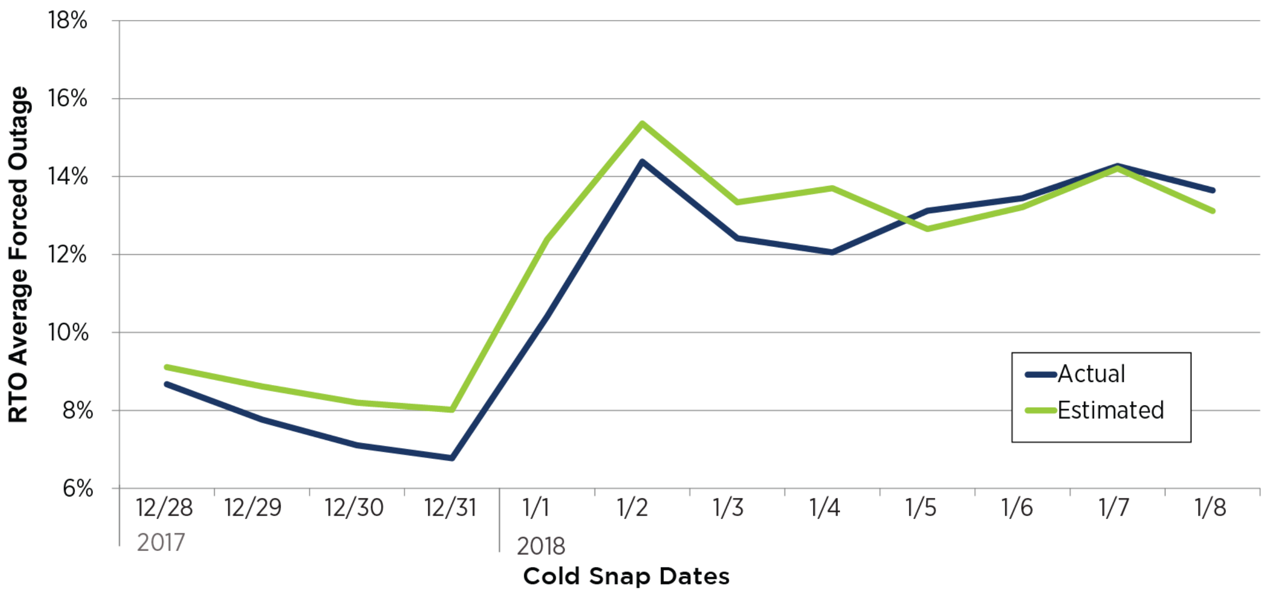


Table 5. Extreme Winter: Resource Type Specific Forced Outage Rates

Coal	11.77
Gas Combined Cycle*	16.91
Gas CT*	9.13
Gas Steam*	15.24
Hydro	11.76
Nuclear	2.38
Oil CT*	11.95
Oil Steam*	12.14
Biomass/Landfill Gas/Wood	18.28

* Calculations exclude forced outages with "Fuel Supply" NERC GADS cause code

Fuel Prices

Figure 18 is a hypothetical example illustrating the fuel price calculation. For instance, fuel price volatility for Dec. 2, 2011, is $(0.10). This is obtained by subtracting the Dec. 1, 2011, fuel price of $1.50 from Dec. 2, 2011, fuel price of $1.40. This historical fuel price delta of $(0.10) is then added to January 2024 futures fuel price of $2.00 to calculate the daily fuel price for the corresponding future date, which results in a $1.90 fuel price.

[22] Fuel supply-related outages for natural gas and oil were estimated, however excluded from the forced outages used in the PLEXOS simulation and are not represented in the displayed averages.

Figure 18 Methodology Example

Day (12/2011)	Commodity A*	Day to Day Differencing	Future Price Difference
1	$1.50		$2.00
2	$1.40	($0.10)	$1.90
3	$1.40		$1.90
4	$1.40		$1.90
5	$1.60	$0.20	$2.10
6	$1.75	$0.15	$2.25
7	$1.65	($0.10)	$2.15

Jan. 2024 Commodity A Future Price as Initial Price ($2.00)

* Commodity: Applicable oil and natural gas contracts

Security Constrained Economic Dispatch Results: Scenario Summaries

PJM developed a common overview template to be applied to each scenario to illustrate the differences in operational impact across scenarios. Seven examples of scenarios using this template were presented as part of the stakeholder process, and are discussed in the sections below. Four of the examples pertain to the announced retirement portfolio and three examples pertain to the escalated 1 retirement portfolio. The scenarios in all seven examples include the looped 2 pipeline disruption, which had the highest amount of impacted generation of the four gas pipeline disruptions.

Each model overview includes four sections summarizing the results of the scenario: scenario summary, system overview, hourly zonal average LMP and oil inventory.

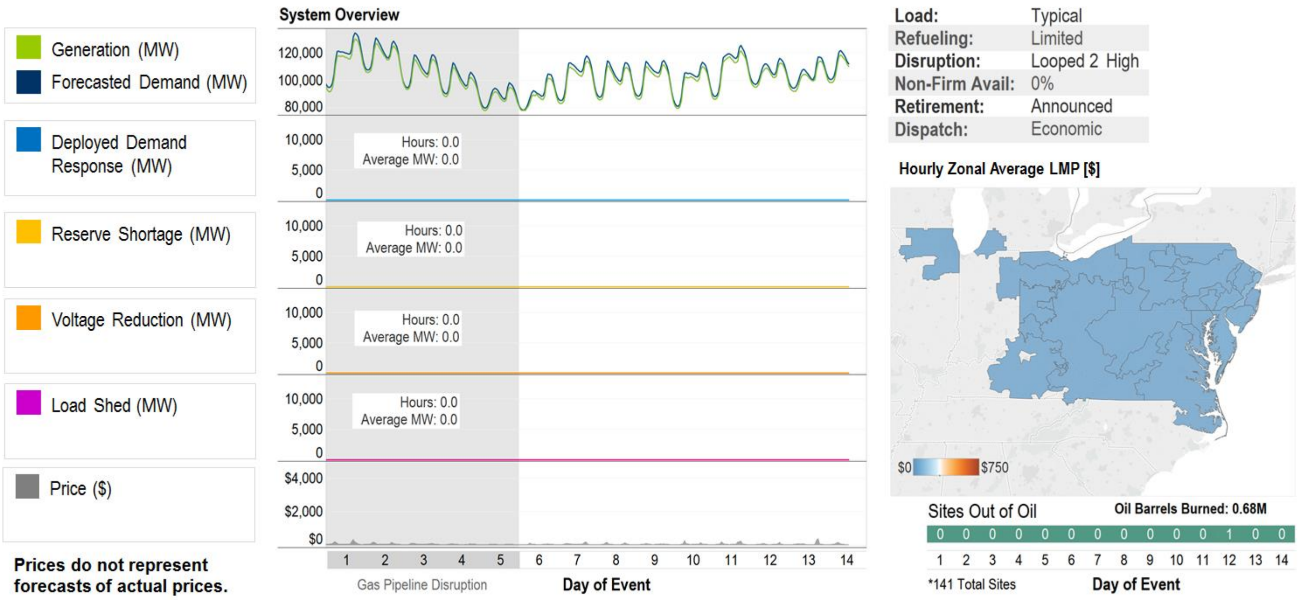
- **Scenario summary:** The scenario summary is listed in the top right-hand corner and describes the input assumptions associated with the scenario.
- **System overview:** The system summary is presented on the left side of the model overview and provides hourly data for generation and demand, demand response, reserve shortage, voltage reduction, load shed and price.
  - **Generation and demand** summarize the hourly load profile and generation at the RTO level.
  - **Demand response (DR)** summarizes hourly DR deployments. DR deployment is a pre-emergency action.
  - **Reserve shortage** summarizes hourly reserve shortage data. A reserve shortage triggers voltage reduction and load shed warnings; these are emergency procedures. Reserve shortage is triggered when the 10-minute synchronized reserves are less than the largest generator in the RTO.
  - **Voltage reduction** summarizes hourly voltage reduction action data. A voltage reduction action is an emergency action. A 5 percent Voltage Reduction Action can result in an approximate 1 percent to 2 percent load reduction.
  - **Load shed** summarizes hourly manual load shed action data. A load shed action is the last resort emergency action for system control.
  - **Price** summarizes hourly RTO locational marginal price (LMP). It is important to note that prices coming out of the simulation are products of the input assumptions and do not represent forecasts of actual prices.
- **Hourly zonal average LMP:** Hourly zonal average LMP data is in the middle of the right side of the model overview. These prices are shown as an indicator for price separation, but it is important to note that prices coming out of the model do not represent forecasts of actual prices.

- **Oil inventory:** Oil inventory statistics are summarized on the bottom right of the model overview. The heat maps indicate, by day, the number of sites where oil inventories were depleted throughout the simulation. This site-specific data refers to on-site fuel inventories for individual generating units or that are shared by a group of generating units.

Example A

Figure 19 summarizes the economic dispatch results for Example A: announced retirement portfolio under typical load conditions with 0 percent non-firm gas availability, limited oil refueling, and looped 2 high-impact pipeline disruption.

Figure 19 Model Overview for Example A



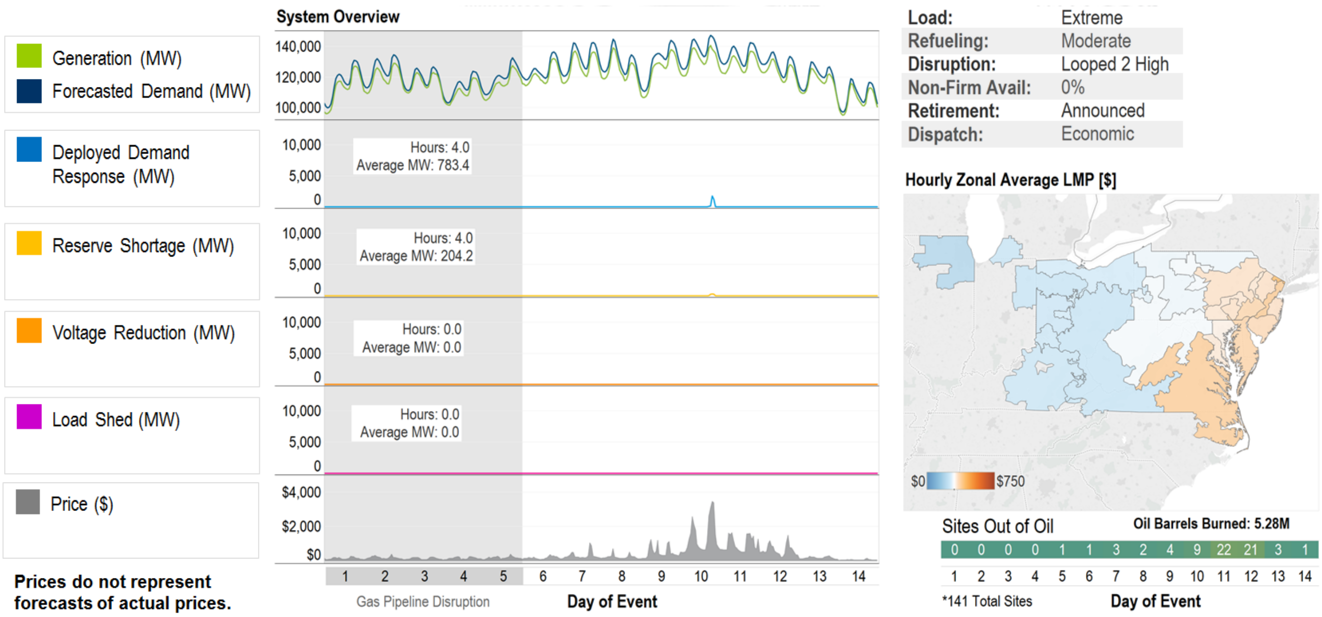
- **System overview:**
  - **Demand response (DR)** was not required in this scenario.
  - **Reserve shortage** was not required in this scenario.
  - **Voltage reduction** was not required in this scenario.
  - **Manual load shed** actions were not required in this scenario.
  - **Price.** The average hourly RTO LMP was $56.00.
- **Hourly zonal average LMP:** Price separation was not observed.
- **Oil inventory:** Only one day of oil depletion was observed throughout the simulation; one of 141 sites had depleted oil inventories on day 12.

In summary, this scenario produced normal operational conditions, which means it did not produce one or more pre-emergency procedures (demand response or reserve shortage) or emergency procedures (voltage reduction or load shed). This scenario is the most impactful under typical load conditions for the announced retirement portfolio. The key takeaway is that no reliability issues are triggered for the announced retirement portfolio under typical load conditions.

Example B

Figure 20 summarizes the economic dispatch results for Example B: announced retirement portfolio under extreme load conditions with 0 percent non-firm gas availability, moderate oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 20 Model Overview for Example B



- **System overview:**
  - **Demand response (DR)** was implemented in four hours, 1 percent of simulated hours.[23] The average DR amount was 783 MW.
  - **Reserve shortage** was implemented in four hours, 1 percent of simulated hours. The average reserve shortage amount was 204 MW.
  - **Voltage reduction** was not required in this scenario.
  - **Manual load shed** actions were not required in this scenario.
  - **Price.** The average hourly RTO LMP was $373.
- **Hourly zonal average LMP:** The locational price separation observed in this scenario indicates locational impacts on the system.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, one of 141 sites were out of oil. Peak oil depletion, 22 out of 141 sites, occurred on day 11.

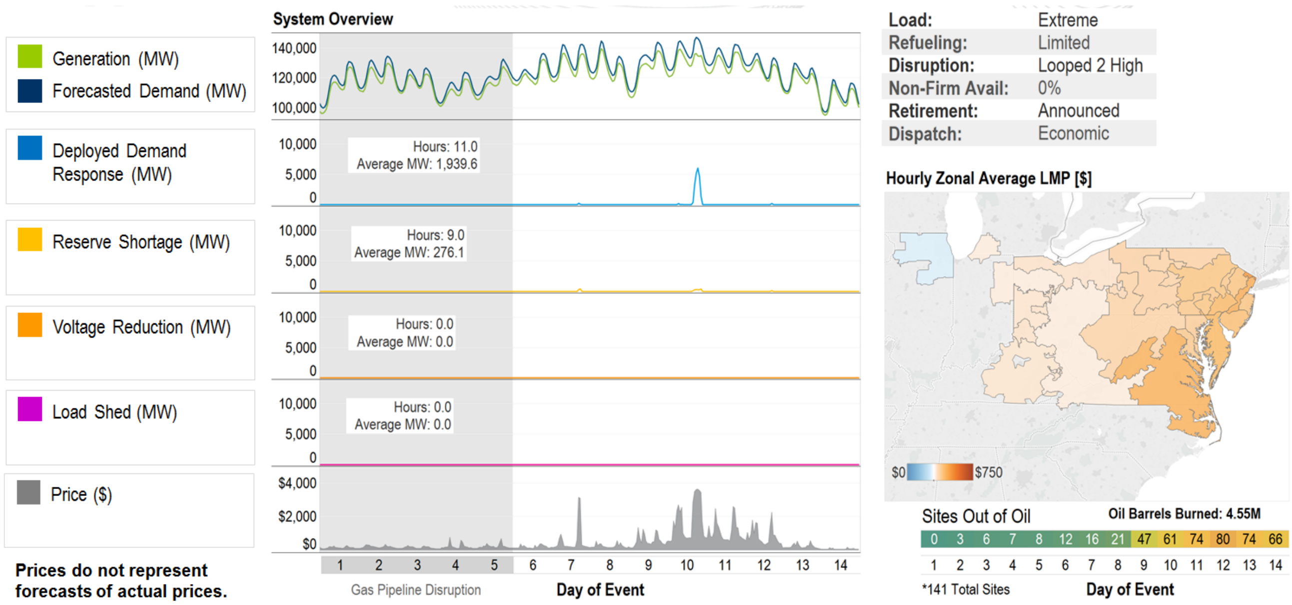
In summary, this scenario triggered small amounts of demand response and reserve shortage when the winter load was shifted from typical to extreme compared to example A. Although pre-emergency procedures were triggered, the system remained reliable.

[23] The total duration of the study is 336 hours.

Example C

Figure 21 summarizes the economic dispatch results for Example C: announced retirement portfolio under extreme load conditions with 0 percent non-firm gas availability, with limited oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 21 Model Overview for Example C



- **System overview:**
  - **Demand response (DR)** was implemented in 11 hours, 3 percent of simulated hours.[24] The average DR amount was 1,939 MW.
  - **Reserve shortage** was implemented in nine hours, 2.6 percent of simulated hours. The average reserve shortage amount was 276 MW.
  - **Voltage reduction** was not required in this scenario.
  - **Manual load shed** actions were not required in this scenario.
  - **Price.** The average hourly RTO LMP was $460.
- **Hourly zonal average LMP:** The locational price separation observed in this scenario indicates locational impacts on the system.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, eight of 141 sites were out of oil. Peak oil depletion, 80 out of 141 sites, occurred on day 12.

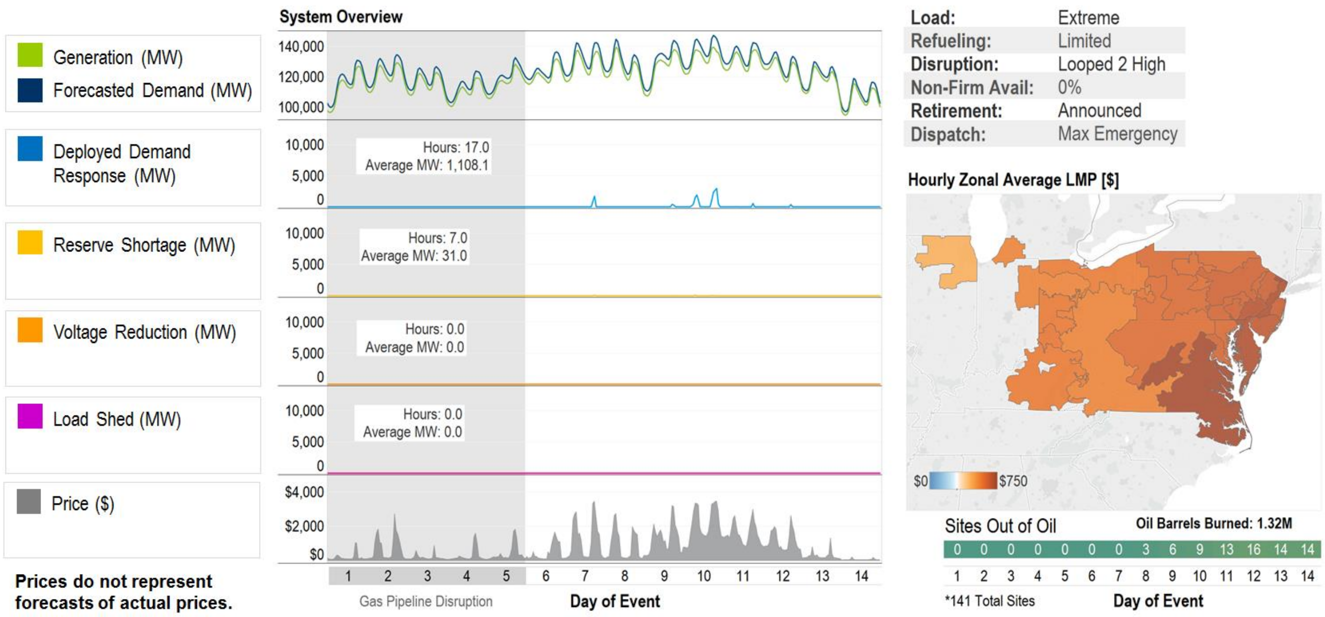
This scenario was the most extreme announced retirement portfolio scenario, and triggered increased amounts of demand response and reserve shortage compared to Example B. This can partially be attributed to the additional limitations on oil refueling. Although pre-emergency procedures were triggered, the system remained reliable.

[24] The total duration of the study is 336 hours.

Example D

Figure 22 summarizes the max emergency dispatch results for Example D: announced retirement portfolio under extreme load conditions with 0 percent non-firm gas availability, limited oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 22 Model Overview for Example D



- **System overview**:
  - **Demand response (DR)** was implemented in 17 hours, 5 percent of simulated hours.[25] The average DR amount was 1,108 MW.
  - **Reserve shortage** was implemented in seven hours, 2 percent of simulated hours. The average reserve shortage amount was 31 MW.
  - **Voltage reduction** was not required in this scenario.
  - **Manual load shed** actions were not required in this scenario.
  - **Price.** The average hourly RTO LMP was $783.
- **Hourly zonal average LMP:** The locational price separation observed in this scenario indicates locational impacts on the system.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, no sites were out of oil. Peak oil depletion, 16 out of 141 sites, occurred on day 12.

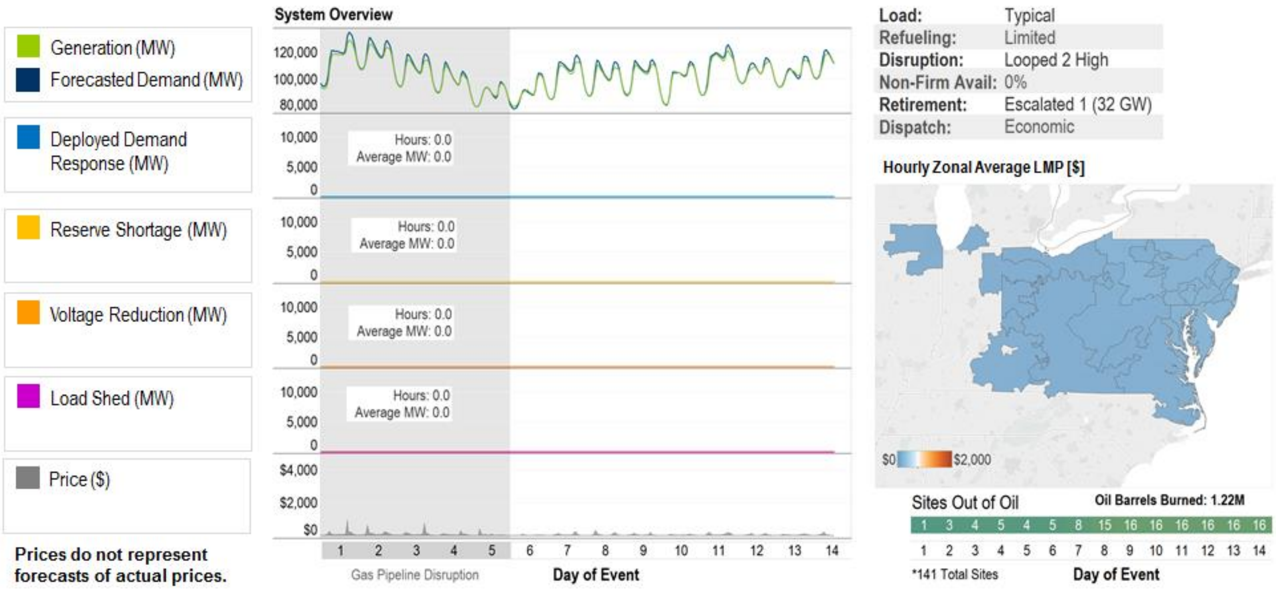
This scenario shows the impact of the ability of the max emergency operational procedure to conserve fuel and reduce the severity of the results compared to example C.

[25] The total duration of the study is 336 hours.

Example E

Figure 23 summarizes the economic dispatch results for Example E: escalated 1 retirement portfolio under typical load conditions with 0 percent non-firm gas availability, limited oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 23 Model Overview for Example E



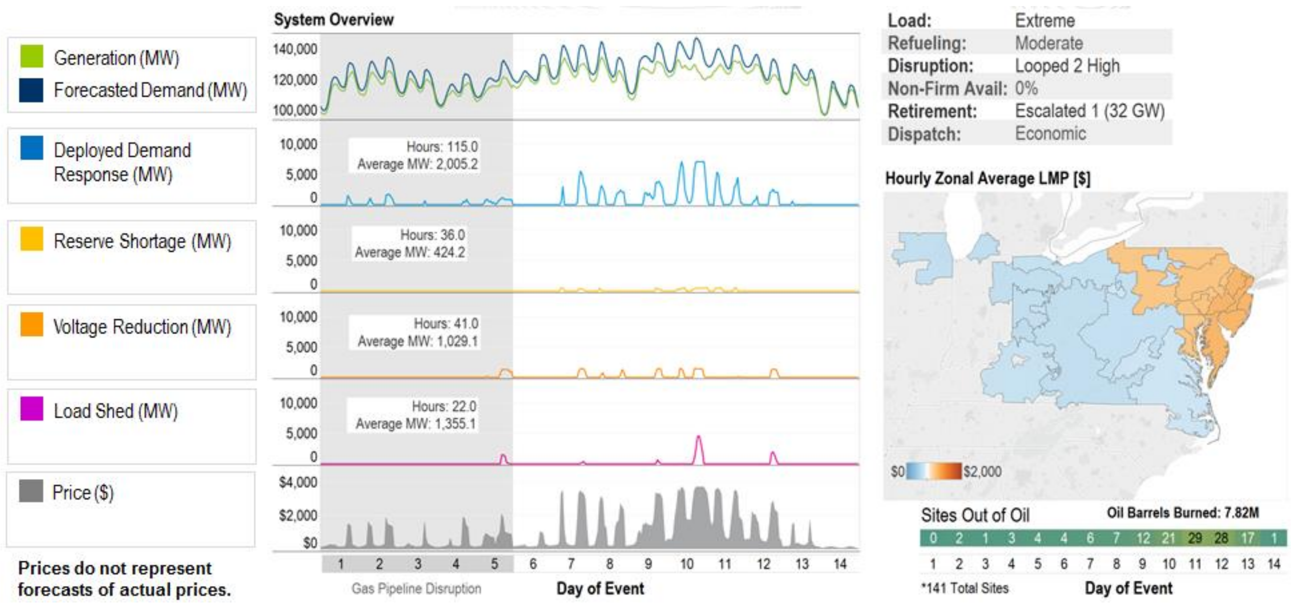
- **System overview**:
  - **Demand response (DR)** was not required in this scenario.
  - **Reserve shortage** was not required in this scenario.
  - **Voltage reduction** was not required in this scenario.
  - **Manual load shed** actions were not required in this scenario.
  - **Price.** The average hourly RTO LMP was $76.
- **Hourly zonal average LMP:** Price separation was not observed.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, four of 141 sites were out of oil. Peak oil depletion, 16 out of 141 sites, occurred on days 9 through 14.

In summary, this scenario produced normal operational conditions, which means it did not produce one or more pre-emergency procedures (demand response or reserve shortage) or emergency procedures (voltage reduction or load shed). This scenario is the most impactful under typical load conditions for escalated retirements; the key takeaway is that no reliability issues are triggered for escalated retirement portfolios under typical load conditions.

Example F

Figure 24 summarizes the economic dispatch results for Example F: escalated 1 retirement portfolio under extreme load conditions with 0 percent non-firm gas availability, moderate oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 24 Model Overview for Example F



- **System overview:**
  - **Demand response (DR)** was implemented in 115 hours, 34 percent of simulated hours.[26] The average DR amount was 2,777 MW.
  - **Reserve shortage** was implemented in 36 hours, 11 percent of simulated hours. The average reserve shortage amount was 424 MW.
  - **Voltage reduction** actions were required in 41 hours, 12 percent of simulated hours.
  - **Load shed** actions were required in 22 hours, 7 percent of simulated hours. The average load shed amount was 1,355 MW. In total, 30 GWh of manual load shed was required.
  - **Price.** The average hourly RTO LMP was $935.
- **Hourly zonal average LMP:** The locational price separation observed in this scenario indicates locational impacts on the system.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, four of 141 sites were out of oil. Peak oil depletion, 29 out of 141 sites, occurred on day 11.

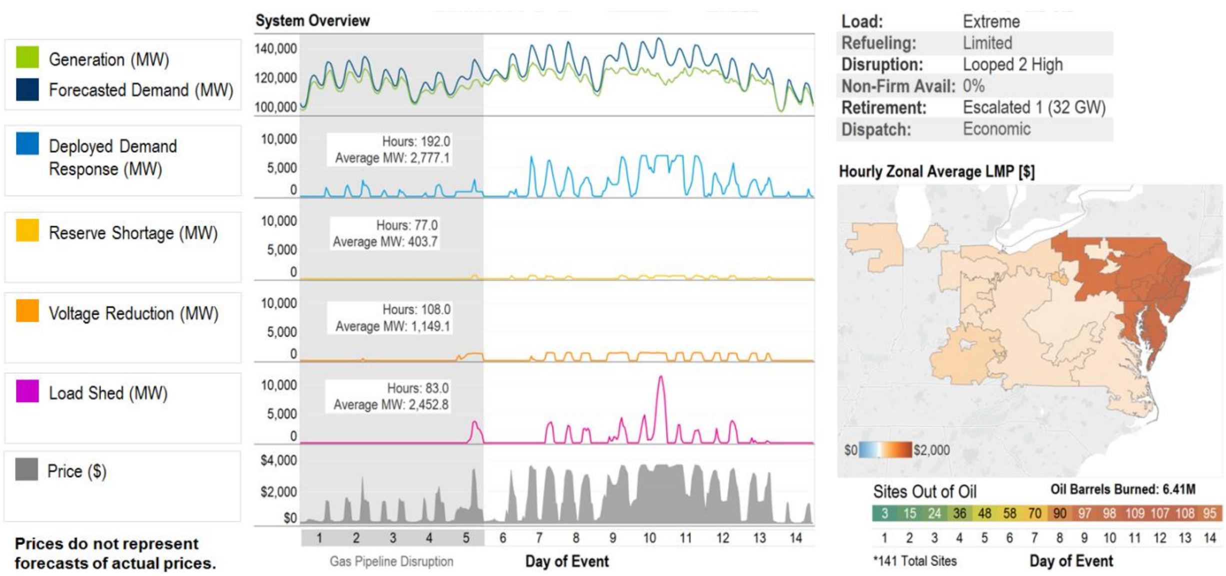
In summary, this scenario resulted in some DR, reserve shortage, voltage reduction actions and load shed actions. Key contributing factors include: level of retirements and replacements reducing the installed reserve margin from the current 28.5 percent to the 15.8 percent requirement, a reduction of available non-firm to 0 percent, and a high-impact pipeline disruption. Moderate ability to replenish oil supplies resulted in less severe results compared to Example G.

[26] The total duration of the study is 336 hours.

Example G

Figure 25 summarizes the economic dispatch results for Example G, the most extreme scenario: escalated 1 retirement portfolio under extreme load conditions with 0 percent non-firm gas availability, limited oil refueling, and the looped 2 high-impact pipeline disruption.

Figure 25 Model Overview for Example G



- **System overview:**
  - **Demand response (DR)** was implemented in 192 hours, 57 percent of simulated hours. The average DR amount was 2,777 MW.
  - **Reserve shortage** was implemented in 77 hours, 23 percent of simulated hours. The average reserve shortage amount was 404 MW.
  - **Voltage reduction** actions were required in 108 hours, 32 percent of simulated hours.
  - **Load shed** actions were required in 83 hours, 25 percent of simulated hours. The average load shed amount was 2,453 MW. In total, 204 GWh of manual load shed was required.
  - **Price.** The average RTO hourly LMP was $1,474.
- **Hourly zonal average LMP:** The locational price separation observed in this scenario indicates locational impacts on the system.
- **Oil inventory:** On day 5, the last day of the pipeline disruption, 48 of 141 sites were out of oil. Peak oil depletion, 109 out of 141 sites, occurred on day 11.

This scenario resulted in the most significant levels manual load shed actions. Key contributing factors include: level of retirements and replacements reducing the installed reserve margin from the current 28.5 percent to the 15.8 percent requirement, a reduction of available non-firm to 0 percent, limited ability to replenish oil supplies, a high-impact pipeline disruption.