Testimony of

Nicholas K. Akins

Chairman, President and Chief Executive Officer

American Electric Power

Before the

Senate Energy and Natural Resources Committee

Hearing on the Impact of Generation Retirements on Electric Reliability

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Good morning Chair Landrieu and Ranking Member Murkowski, members of the Committee and fellow panelists. My name is Nicholas K. Akins, and I am Chairman, President, and Chief Executive Officer of American Electric Power (AEP).

AEP is one of the largest electric utilities in the United States, delivering electricity to more than 5.3 million customers in 11 states. AEP owns nearly 38,000 megawatts of generating capacity in the U.S. and the nation's largest electricity transmission system, a 40,000-mile network that includes 2,100 miles of 765-kilovolt extra-high voltage transmission lines. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's headquarters is in Columbus, Ohio.

Today's hearing is focused on electric grid reliability and security, and whether we are doing enough to address significant challenges to the grid.

We are beginning to make progress as evidenced by the fact that this hearing is occurring today and is one of the first under Chair Landrieu. The white paper authored by Senator Murkowski provided excellent background and potential solutions. Additionally, Federal Energy Regulatory Commission (FERC) Acting Chair Cheryl LaFleur has recognized the challenges facing the gas and electric industries. However, we need to do more to ensure that we maintain a diverse portfolio of generation reserves, and we need to do it sooner rather than later. This country's grid was tested in January, and we passed, but barely.

A month ago, I made headlines when I said 89 percent of the generation that AEP will be retiring in 2015 was called upon to meet electricity demand in January. That is a fact. These units were called upon by PJM and relied upon to maintain regional reliability. In making this statement, I am not saying we should abandon or postpone the Mercury and Air Toxics Standards (MATS) rule. Nor am I saying we should avoid building more natural gas-fueled powered plants. What I am calling attention to is the fact that our nation's fleet of power plants is undergoing a significant transition, and we need to ensure that the electric system that the American economy relies upon is equipped to serve that need in a reliable manner. AEP has been sounding the alarm on long-term reliability for several years now and time is running out.

The current capacity markets are not functioning as intended. From my perspective, the current structure of the capacity markets is not attracting a mix of new generating resources that will keep the lights on, nor providing the correct pricing signals for the existing fleet. This, coupled with the high number of base load unit retirements, jeopardizes the reliability of the grid.

Most of the new capacity being offered is either gas or demand response. There are a host of difficulties in coordinating the gas and electric industries, and demand response continues to be paid similar capacity prices to steel-in-the-ground generation despite having rules and penalty provisions that are much less prescriptive.

The Polar Vortex: A Warning Signal

During this past winter, PJM was faced with certain challenges that threatened the reliability of the electric grid. PJM set a new all-time winter peak load of 141,846 megawatts on January 7, 2014. In fact, eight of PJM's top 10 all-time winter peaks occurred in January 2014.[1]

At the same time that peak demands were being set, approximately 22 percent of total installed generation capacity in PJM was unavailable.[2] Some generation units experienced forced outages resulting from equipment failure, cold temperature operations and some fuel supply issues. The initial polar vortex event at the beginning of January was an extreme, followed by continuing arctic weather throughout the month. The polar vortex represented only two of the 10 days PJM needed to call on Emergency Operating Procedures.[3] Fortunately, the system operated without a loss of load event. It could have been much worse. As FERC Acting Chair LaFleur said at the April 1 FERC technical conference, "We had a difficult winter for both the electric

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[1] Polar Vortex 2014, Michael Kormos, PJM, FERC Technical Conference Presentation, p. 3

[2] Polar Vortex 2014, Michael Kormos, PJM, FERC Technical Conference Presentation, p. 6

[3] http://www.pjm.com/~/media/committees-groups/committees/mc/20140224-webinar/20140224-item-01-winter-operations.ashx. Slide 6 on Cold Weather Operations report.

and gas infrastructure and markets across the country. As others have noted, the system bent but it did not break. Reliability was sustained, but at times was very close to the edge."[4]

The weather events experienced this winter provided an early warning about serious issues with electric supply and reliability. PJM was not alone. Many of the Regional Transmission Organizations (RTOs) and Balancing Authorities needed to call on Emergency Procedures to ensure reliable operations. This country did not just dodge a bullet – we dodged a cannon ball.

We need to take action now to ensure adequate power plant capacity, fuel diversity and grid investment after the retirement of significant amounts of base load generation in mid-2015 and beyond. Because the base load generation that will retire in 14 months will not be fully replaced, this reliability concern is imminent and is a concern we need to proactively address.

Although average consumers may not be well versed on the intricacies of grid reliability, after examining their power bills, they will understand all too well the price volatility that comes with it. We are focused today on reliability, but price signals – and there have already been high price signals – are a symptom of reliability threats. FERC Acting Chair LaFleur summed it up well at a technical conference last week when she said, "I'm also very concerned about price, both the absolute magnitude of the price spikes and the increases we saw this winter and the

[4] http://ferc.capitolconnection.org/

variability. When you see these price spikes, it's a symptom that protecting reliability is causing this issue."[5] She is absolutely correct.

Reliability Impacts: Flawed Capacity Markets

Reliable electric service is a critical public need. Our nation's economic success depends upon our ability to preserve this fundamental resource. To that end, we must ensure that we have the necessary long term investment to maintain reliability. The competitive wholesale markets are not currently providing the structure necessary to maintain that reliability and do not currently provide the proper economic signals to foster new power plant investment for the future.

The real value of steel-in-the-ground capacity must be recognized in the competitive markets. Insufficient revenues from both the capacity and the energy markets mean additional nuclear and fossil generation may be retired. We already have the retirement of the Kewaunee Nuclear Plant in Wisconsin. This 556-megawatt facility was retired May 7, 2013, ending a 40-year service life. Plant owner Dominion Power said "this decision was based purely on economics."[6] Vermont Yankee in New England, owned by Entergy, closed for the same reason.[7]

Exelon announced last month that they will consider closing efficient nuclear plants by the end of this year because they are no longer profitable. Exelon's CEO Chris Crane told the

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[5] http://ferc.capitolconnection.org/

[6] Dominion news release, May 7, 2013.

[7] http://www.entergy.com/vy/

Chicago Tribune that, "Despite our best-ever year in generation, some of our nuclear units are unprofitable at this point in the current environment, due to the low prices and the bad energy policy that we're living with. A better tax policy and energy policy would be the clear answer, but if we do not see a path to sustainable profits, we will be obligated to shut units down to avoid the long-term losses."[8]

Even PJM's market, which is probably the most developed in the country, does not provide the type of long-term price signals that encourage and support investment. This lack of investment, coupled with announced retirements, puts reliability at risk.

The market flaws that create economic inefficiencies include inequities in the treatment of actual generating assets versus demand response (DR), imported power and even new planned generation. Yes, PJM has more than 8,000 megawatt of planned (mostly gas) generation[9] identified in the last two auctions, but many of those generators are being proposed with some form of state regulatory funding support. What this means is that many new builds are the result of state directives rather than a response to market signals. Other market design problems exist with demand response compensation. While existing generators are required to be available for dispatch when needed and face financial penalties for failure to respond, most demand response is only required to perform in the summer.[10] Even then, most of the summer demand response is only required to perform 10 times a summer for a maximum of six hours each time. In PJM, only

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[8] *Chicago Tribune,* March 9, 2013, Business Section, page 1

[9] The PJM "2016/2017 RPM Base Residual Auction Results" report (page 1).

[10] The PJM "2016/2017 RPM Base Residual Auction Results" report (page 10) shows that of the 12,407MWs of DR cleared for 2016/17, only 88MWs were available year-round.

1,911 megawatts of demand response voluntarily responded at the peak on January 7.[11] A total of 12,000 megawatts of demand response cleared the PJM capacity auction for 2016/17.[12] This comprises about half of the PJM reserve margin for 2016/17, and 99 percent of that demand response is a summer-only resource.[13]

Importing power from plants in other reliability regions can also be an issue. On July 15, 2013, a Tennessee Valley Authority transmission constraint, exacerbated by the reduction of a MISO resource, resulted in the curtailment of more than 3,300 megawatts of PJM imports,[14] including 29 megawatts of imports on firm transmission[15]. This is the reliability risk of depending on imported power. PJM has cleared power imported from Louisiana in its capacity auction, although the ability of that Louisiana power to ever be delivered into PJM territory during emergency conditions is problematic at best.

Currently, PJM's three-year Base Residual Auctions are augmented with annual incremental auctions. Demand response resources can bid into the Base Residual Auction at one price, and buy back their own resources in the incremental auctions at a nice profit, and never

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[11] PJM Emergency Demand Response (Load Management) Performance Report 2013/2014

[12] PJM "2016/2017 RPM Base Residual Auction Results" report (page 10), Table 3B.

[13] Slide 13 of Kormos presentation at April 1, 2014 FERC Tech Conference on Polar Vortex. Target Reserve level is approximately 25,000 MWs. DR cleared for 2016/17 was approximately 12,000MWs.

[14] http://www.pjm.com/~/media/committees-groups/committees/mrc/20130829/20130829-item-13-hot-weather-operations-presentation.ashx. Slides 8 and 9.

[15] http://www.pjm.com/~/media/committees-groups/committees/mrc/20130829/20130829-item-13-hot-weather-operations-presentation.ashx. Slides 8 and 9.

have to perform a demand response function for reliability.[16] PJM's Independent Market Monitor has issued two reports on this problem.[17] As much as 57.6 percent of demand resources have purchased replacement capacity in the incremental auctions. The average over the seven-year measurement period was 32.5 percent.[18] These speculative resources are replacing the actual physical generation we need because it is financially more lucrative to buy back in the incremental auctions than to deliver the capacity.[19] Nor does demand response provide the very important ancillary services currently provided by many of the retiring generating units.

Beyond the demand response issue, PJM went into 2013/14 with a 20 percent reserve margin, but called 10 emergency operations in January 2014.[20] PJM has conducted auctions for 10 planning years and the average clearing price has been $90/megawatt-day.[21] This is less than 30 percent of the Net Cost of New Entry (CONE)[22] and may not be enough to sustain existing units, let alone entice new construction. PJM has made several filings recently to try to eliminate the speculative bidding that has made it more profitable to be a financial player in PJM than offer

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[16] Latest report is *Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013.*

[17] Latest report is *Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013.*

[18] Ibid., Table 8

[19] http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf. Page 35. The Market Monitor in referring to the high percentage of replacements being done by demand resources says, "The result is an increasing share of total capacity resources that are limited DR, which are clearly not a substitute for generating capacity which is on call 8,760 hours per year."

[20] http://www.pjm.com/~/media/committees-groups/committees/mc/20140224-webinar/20140224-item-01-winter-operations.ashx. Slide 6 on Cold Weather Operations report.

[21] Average taken from all 10 Base Residual Auction reports for Rest-of-market 2007/08 through 2016/17.

[22] Net CONE for 2016/17 was $330/MW-day.

up real generation resources. I applaud those efforts. Although PJM is trying to correct many of these shortcomings through FERC filings, it is not enough.

In the next 14 months, AEP will retire almost a quarter of our coal-fueled generating units. We have one of the largest generation fleets in the country, and one-fourth of our coal-fueled capacity will be shuttered. There is no turning back for these units. In PJM, 13,000 megawatts of additional capacity will be retiring by mid-2015.[23] Unless the market structure changes, the capacity replacements for these assets may not provide the same level of reliability we have experienced historically.

AEP believes that capacity prices should be augmented by a reliability adder, or price floor. This would support continued operation of base load generating units and provide incentives (and penalties) to spur construction of new generation. We also believe a longer-term commitment for price certainty would help all companies with both existing and new assets to make long-term investment decisions. Power plant investments are for 30+ years. A reliability adder combined with a longer-term award would provide proper incentives, ease financing, and provide longer-term price stability for the markets, all of which will preserve and increase grid stability.

Reliability Impact: The Dash to Gas

These situations are exacerbating a dash to gas as the nation looks for quick alternatives to our retiring base load plants. Incongruities in the gas and electric markets create a new set of problems.

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[23] Andy Ott's presentation at February 12, 2014, PJM General Session, page 3.

Inconsistencies in scheduling protocols between the gas and electric industries create difficulties for many gas-fired electric generators. These inconsistencies can make it challenging for gas-fueled generators to purchase gas supplies and schedule pipeline capacity.

The coordinated operation of the natural gas and the electric industries is not impossible. In fact, in AEP's southwestern footprint, we have been coordinating our industries fairly well for years. It is important to realize that no one is at fault for the disconnect between the two industries. The industries matured independently, and they developed unique operating procedures that worked well for their individual businesses. Now that they both have operating protocols that have been in place for decades, we need to find a way to successfully merge their processes.

In New England during the polar vortex, it became clear that we are having to make a choice in the winter between committing natural gas resources to generating electricity or to heating homes.[24] Right now, we cannot do both. Given the number of additional base load generating units that will be retired in the next 14 months, we face a very real possibility that we will have to make that choice more often in the future.

Many of the issues of harmonizing the gas and electric industries revolve around scheduling. FERC currently has three open dockets related to scheduling. RM14-2-000, the primary docket, has adopted a unique approach to resolving the scheduling problems. FERC has offered new scheduling procedures and steps to bring the gas and power days closer together. FERC has charged the North American Energy Standards Board (NAESB) with reaching full industry consensus for both industries within six months. NAESB is the nation's only

[24] http://www.forbes.com/sites/jamesconca/2014/01/12/polar-vortex-nuclear-saves-the-day/

organization that reaches across both industries and NAESB is ANSI certified for standards development. NAESB's window to reach consensus will be followed with a public comment period on the NAESB proposals. If NAESB cannot reach consensus in the time allotted, the FERC proposals in RM14-2-000 will, after notice and comment, become the new scheduling standards.

AEP is supportive of the FERC natural gas proposals in the Notice of Proposed Rulemaking (NOPR). Currently the gas day begins at 9 a.m. Central Clock Time (CCT), all across the country.[25] The power day begins at midnight in the time zone in which the energy is generated.[26] FERC proposes moving the start of the gas trading day to 4 a.m. CCT, which allows power traders to purchase the gas supply they need in time to receive delivery for their morning peak load. RM14-2-000 also proposes adding nomination cycles to the current four cycles (two real-time cycles and two day-ahead).

These two changes would resolve several of the timing issues that currently either a) require gas generators to purchase fuel for much longer times than what they really need, increasing their costs as they buy far more fuel than is actually required or b) force gas generators to risk not getting a gas supply if they wait to buy gas until after their dispatch awards. For example, under the current rules generators have to purchase fuel for Monday on Friday afternoon, and they cannot always predict that far ahead exactly how much gas they will need.

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[25] Appendix F, page 19

[26] Appendix G, page 19

With the growing dependence on natural gas for electricity generation, availability and deliverability of gas must be considered in RTO planning and when setting generation reserve requirements. In general, gas cannot be stored on site at an electric generation plant in sufficient quantities to guarantee future fuel supply. Meanwhile, gas pipelines are looking for firm transport contracts, meaning they want a reservation fee for the full capacity of a generating station for every hour of the year. Many of these gas plants are peakers, generating units that only operate during peak demand periods, and only need the gas reservation for a small portion of the year.

Most capacity markets do not require a firm contract in order for a generator to be counted as reliable capacity. If all gas-fueled generators were required to obtain firm transport contracts, the result would be much higher electricity costs. This would improve reliability somewhat, but even firm transport does not guarantee availability of the gas supply. Discounted non-firm transport carries even more reliability issues. Further, in many cases the location of a gas unit precludes the ability to obtain firm gas supply because it is on a pipeline that is already fully subscribed.

Reliability Impact: Generation is Retiring

Prior to implementation of MATS, we did not have an adequate assessment of the impact of these environmental regulations on our nation's base load generation. When the MATS rule was proposed, the U.S. EPA projected that the rule would result in approximately 10,000 megawatts of coal-fueled generation being retired.[27] More recently, NERC's 2013 *Long Term Reliability Assessment* places the retirement number at 62,800 megawatts by 2023.[28] Not all of these retirements are due to MATS, with lower natural gas prices, weak electric demand and flawed markets all playing a role. But the timing of many of the retirements will be driven by the MATS compliance deadline.

AEP will retire an additional 6,586 megawatts (approximately 1/4 of its coal-fueled capacity) with most retirements occurring in mid-2015.[29] We will not add any new capacity in the near term. The total PJM capacity market is approximately 169,000 megawatts.[30] According to PJM, more than 9,827 megawatts of generation already has been shut down since the 2007/08 delivery year and another 12,909 megawatts is scheduled to retire in the next two years.[31] While 8,750 megawatts of new generation that cleared in the PJM capacity auction is supposed to go online in 2015 and 2016, only approximately 4,500 megawatts currently is reported as under construction.[32] Many planned generation plants were offered into the auction or are being built

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[27] National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units, Proposed Rule, 76 Fed. Reg. 24975, 25073 (May 3, 2011).

[28] 2013 *Long-Term Reliability Assessment,* p. 29, North American Electric Reliability Corp

[29] Total retirements per American Electric Power 2013 Corporate Accountability Report are 7,201MW. Of this total, 6,586MW are to be retired between now and mid-2015.

[30] The PJM "2016/2017 RPM Base Residual Auction Results" report (page 1).

[31] Andy Ott's presentation at February 12, 2014, PJM General Session, page 3.

[32] Andy Ott's presentation at February 12, 2014, PJM General Session, page 3 for planned units. 4,280MWs under construction from the Ventyx database monitored by AEP.

only because they have a regulated-type of cost recovery structure (such as in Virginia).[33] Further, almost all of the new generation that was offered in the market in the last several years has been natural gas-fueled; and that is the predominant type of generation that is currently in the planning queue.

Many times, new generation projects are permitted but never built. The average construction time for a gas plant is 2.5 to 3.5 years, depending on the technology used.[34] So even if some of those additional projects are built, I am concerned they will not be online in time to relieve the immediate reliability challenges that stem from the coal-fueled unit retirements.

All of these factors (capacity markets, environmental standards, gas coordination) are significant issues impacting our power generation fleet today. Additional environmental rules still in development could create additional issues. The Cooling Water Intake Rule (316b), the Coal Ash Rule and the Greenhouse Gas New Source Performance Standards all could potentially result in additional base load generation units being retired. The MATS rule implementation did not allow a lot of flexibility in meeting the regulatory standards. If a rational approach with sufficient flexibility is not taken in setting these new environmental standards, we will face additional threats to grid reliability.

[33] Virginia's units are Brunswick and Warren County – total approximately 2500MW. Although the New Jersey and Maryland state-subsidized programs were found to be in violation of the PJM Tariff rules, the units that were awarded in those state-run auctions offered and cleared in the RPM before the state programs were overturned. Some of these units decided to continue to build and some are undecided or continue to have contractual issues.

[34] AEP 2011 Integrated Resource Plan cost model for new units

Resolving Reliability Threats

I am not saying we should repeal MATS. Nor am I saying we should avoid building natural gas power plants. I am saying that we are facing some serious reliability concerns that require quick action.

Regulators at the federal and state levels must recognize and consider the complexity of the transitions and challenges facing the electric grid today. The combination of capacity markets, environmental regulations, and gas coordination issues are potentially a bigger threat to reliability and safety than physical and cyber security violations. Regulated utilities plan for peak usage through integrated resource planning processes. Competitive generators depend on clear market signals to support the investment necessary for stable operations. Megawatts flow seamlessly across state borders. As additional stressors impact the bulk power system in the coming years, state and federal regulators must be vigilant to ensure that regulated customers are not harmed by the scarcity and volatility that will develop if competitive markets are not fixed.

Toward that end, AEP advocates for:

- Significant progress on fixing the capacity markets by January 2015. We need to return the focus of the nation’s electric grid to reliability and away from a financial scheme that rewards speculative activity. That can be achieved through the FERC, and I would encourage this Committee to support the FERC in that effort.
- Passage of legislation to resolve the conflict between the authority of the Department of Energy and that of the Environmental Protection Agency that could manifest in the DOE ordering a unit to run even when that unit would violate environmental requirements. Legislation is needed to clarify the rules and expedite new construction

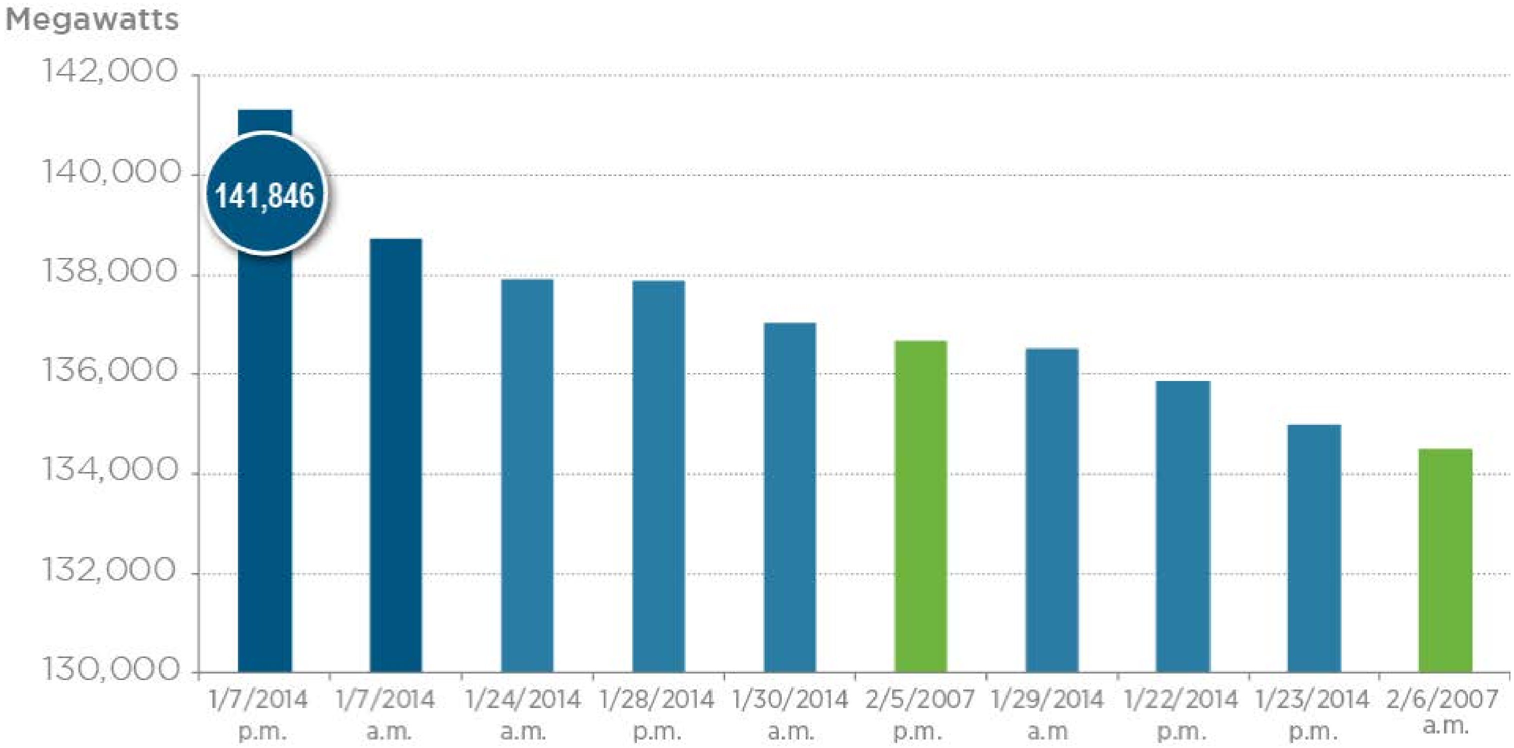
to ensure that existing generation will not have to face a choice between violating the environmental rules and letting the lights go out.

- Completion of the action recently begun by the FERC to coordinate the natural gas and electric industries. I believe FERC has taken important steps in this direction and is doing so as rapidly as possible. We need resolution before next winter. Nothing good comes from a scenario in which anyone has to choose between electricity and heat.

The severe weather this winter highlighted the many challenges that are seriously threating the reliability of our electric grid. These issues are real and they are pressing, and we have been given an opportunity to address them. Few things in this country are as critical as grid reliability. We should not waste this opportunity to ensure that we address the issues challenging our ability to provide reliable electric service. The electric grid powers our economy, our citizens' homes and our national security. And the next cannon ball we see coming at us may not be one we can dodge.

I thank you for the opportunity to address you on these issues. I would be happy to respond to any questions.

APPENDIX A: PJM RTO Highest Historic Winter Demands



Source: *Polar Vortex 2014*, a presentation by Mike Kormos, PJM, to the Federal Energy Regulatory Commission, slide 3

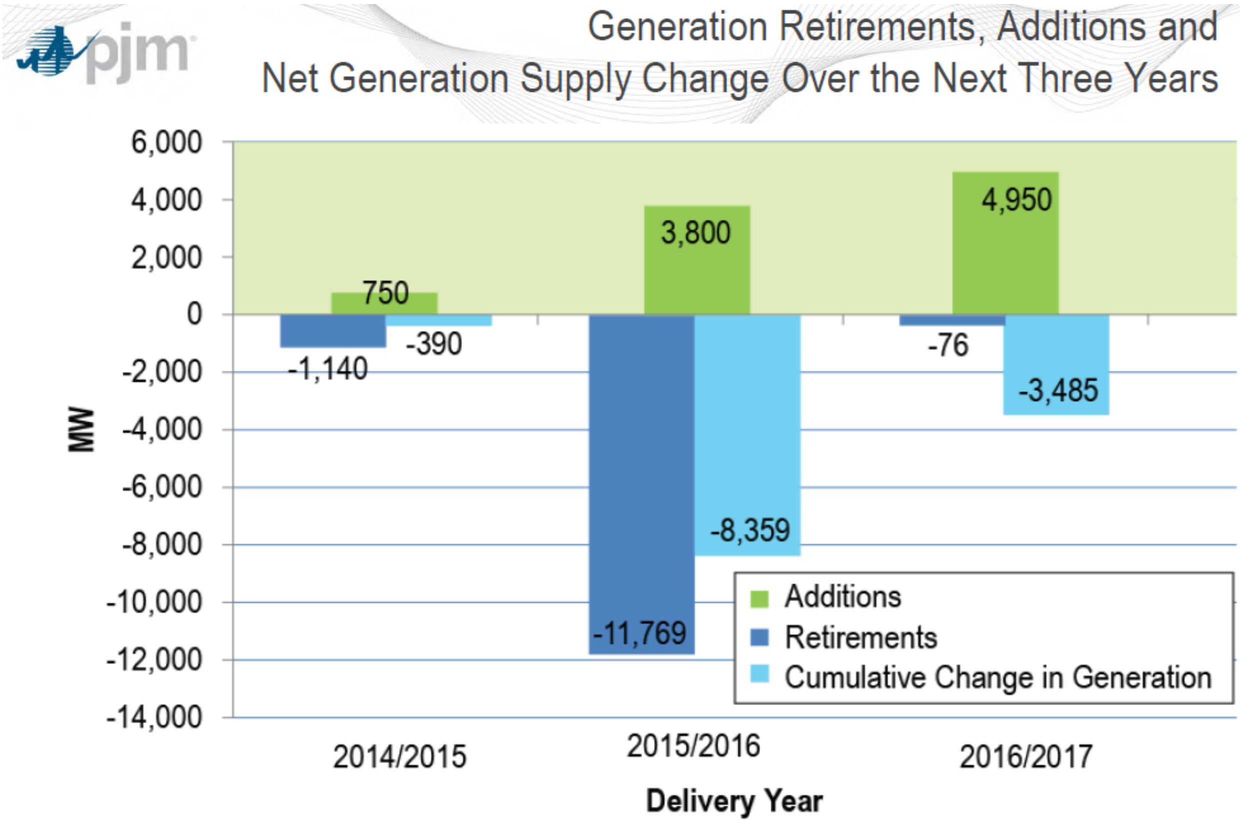
APPENDIX B: PJM Emergency Procedures Implemented During the Polar Vortex

Source: PJM

	Emergency Procedure	MON 1/6	TUE 1/7	WED 1/8	WED 1/22	THU 1/23	FRI 1/24	MON 1/27	TUE 1/28	WED 1/29	THU 1/30
Alerts	Cold weather										
	Max emergency										
	Voltage reduction										
	Primary reserve										
Warnings	Voltage reduction										
	Primary reserve										
Actions	Max Emergency										
	Voltage reduction										
	Reserve action										
	Shortage pricing										
	Emergency energy			*		*					
	Load management										
	C2 conservation										

* Emergency energy bids were requested but not loaded

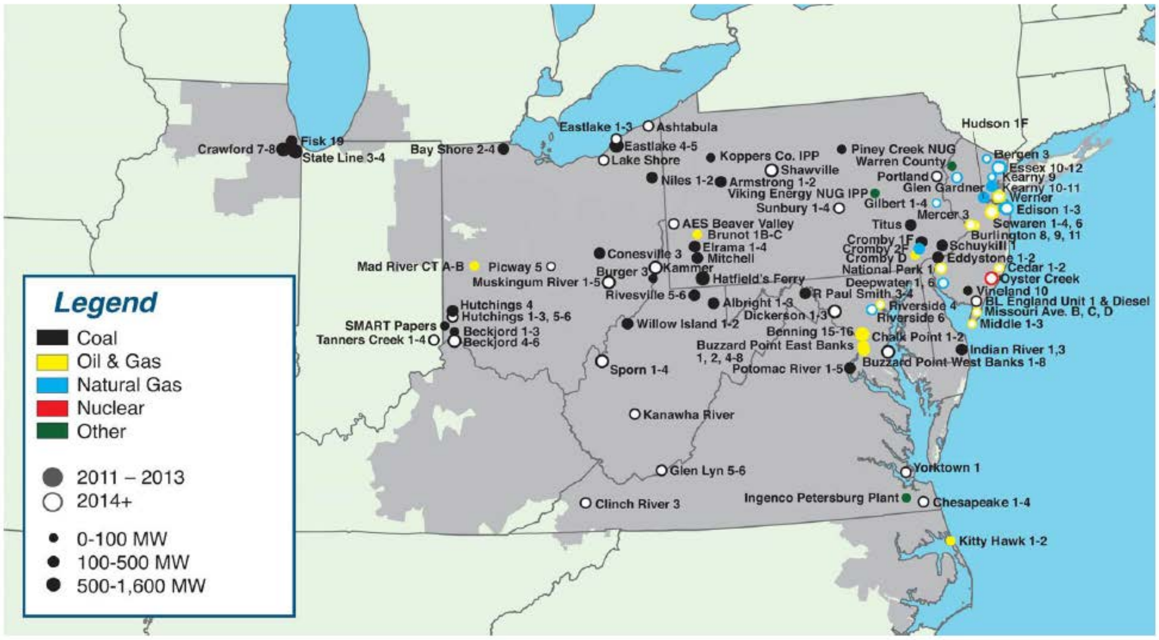
APPENDIX C: Total Capacity in PJM is Decreasing



Source: PJM

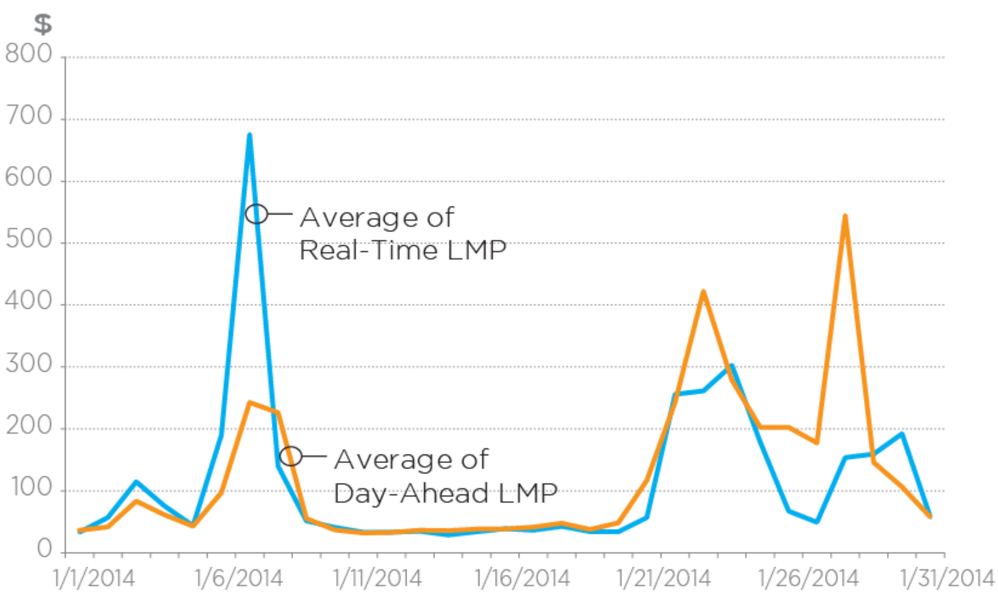
APPENDIX D: PJM Retirements, 2011-2016

Figure 12-1 Map of PJM unit retirements:
2011 through 2019



Source: PJM

APPENDIX E: January PJM Load-Weighted Locational Marginal Prices



Source: PJM

APPENDIX F: Current NAESB Gas Nomination Cycles

NAESB Nomination Cycle	Nomination Time (Central)	Nomination effective	Bumping Interruptible Transportation	Bumping Notice (Central)	Schedule Confirmed (Central)
Timely	11:30 AM the **day prior to gas flow** that would begin at 9:00 AM next day	Day-Ahead	Yes **(1)**	4:30 PM Day-Ahead	4:30 PM Day-Ahead
Evening	6 PM the **day prior to gas flow** that would begin at 9:00 AM next day	Day-Ahead	Yes **(1)**	10 PM Day-Ahead	10 PM Day-Ahead
Intra-Day 1	10 AM the day of gas flow	Day of	Yes **(1)**	2 PM Day of	2 PM Day of
Intra-Day 2	5 PM the day of gas flow	Day of	No **(2)**	Not Applicable	9 PM Day of

(1) A Firm nomination for the first 3 nomination cycles has priority over (can "bump") an already scheduled Interruptible (IT) nomination;
(2) At the Intra-Day 2 cycle, a Firm nomination will not bump an already scheduled Interruptible nomination

Source: NAESB

APPENDIX G: RTO Bid Award Schedules

RTO	Day-Ahead Offer/Bid Due	Day-Ahead Award	Re-Bid Period (for units w/no cleared MW)	Reliability commitment by RTO	Real Time Change for Energy Offer Allowed?
PJM	12 PM Eastern	4 PM Eastern	4-6 PM Eastern	6 PM Eastern and then throughout actual operating day	No (real-time offer based on day-ahead or re-bid offer)
SPP	11 AM Central	4 PM Central	4-5 PM Central	5 PM Central and then throughout actual operating day	Yes, up to 45 minutes prior to the operating hour
ERCOT	10 AM Central	1:30 PM Central	***1** None; *however* uncommitted resources may change their offer at any point 60 minutes prior to operating hour.	2:30 PM Central day-ahead; and then an hourly process up to 60 min prior to operating hour	Yes, up to 60 minutes prior to the operating hour for resources not committed in day-ahead or during day-ahead reliability period
MISO	11 AM Eastern	3 PM Eastern	3 - 4 PM Eastern	4 PM Eastern and then throughout actual operating day	Yes, up to 30 minutes prior to the operating hour