Exhibit No.:	
Issue:	Rate Design
Witness:	James R. Dauphinais
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Noranda Aluminum, Inc.
Case No.:	EC-2014-0224
Date Testimony Prepared:	May 30, 2014

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service)

Case No. EC-2014-0224

NON-PROPRIETARY VERSION

Surrebuttal Testimony and Schedules of

James R. Dauphinais

On behalf of

Noranda Aluminum, Inc.

May 30, 2014

BRUBAKER & ASSOCIATES, INC.

Project 9851

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of James R. Dauphinais

James R. Dauphinais, being first duly sworn, on his oath states:

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Noranda Aluminum, Inc. in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. EC-2014-0224.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

James R. Dauphinais

James R. Dauphinais

Subscribed and sworn to before me this 29th day of May, 2014.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2017
Commission # 13706793

Maria E. Decker

Notary Public

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Surrebuttal Testimony of James R. Dauphinais

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME JAMES R. DAUPHINAIS WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF NORANDA ALUMINUM, INC. ("NORANDA")?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A The purpose of my surrebuttal testimony is to respond to the rebuttal testimonies of Ameren Missouri witness Matt Michels and Staff witness Sarah L. Kliethermes with respect to the impact on Ameren Missouri's Actual Net Energy Cost ("ANEC") of a shutdown of Noranda's New Madrid facilities. I also respond to both witnesses with respect to Midcontinent Independent System Operator, Inc. ("MISO") load-based charges that are not included in Ameren Missouri's ANEC that Ameren Missouri would avoid if Noranda's New Madrid facilities were shutdown.

My colleague, Mr. Brubaker, addresses the other aspects of the rebuttal testimonies of Mr. Michels and Ms. Kliethermes.

The fact that I do not address every point raised by these witnesses, or points raised by other witnesses, should not be interpreted as agreement with those points or those witnesses.

Q YOU INCLUDED A DETAILED EXPLANATION OF AMEREN MISSOURI'S ANEC IN YOUR DIRECT TESTIMONY (DAUPHINAIS DIRECT AT 2-3). PLEASE PROVIDE A VERY BRIEF RECAP.

A ANEC is the portion of Ameren Missouri's revenue requirement that is tracked through Ameren Missouri's Fuel Adjustment Clause ("FAC"). It includes Ameren Missouri's fuel and purchased power costs as reduced by Ameren Missouri's off-system sales revenues. The change in Ameren Missouri's ANEC that would occur from a shutdown of Noranda's New Madrid facilities is of major importance in this proceeding because such a shutdown would essentially result in Ameren Missouri selling the power it currently sells to Noranda into the MISO market instead of to Noranda. This will essentially increase Ameren Missouri's off-system sales revenues (and, as a result, decrease Ameren Missouri's ANEC) by the cost saved by not clearing the Noranda load in the MISO market. As discussed by Mr. Brubaker, this will only partially offset the retail revenues Ameren Missouri would lose from a shutdown of Noranda's New Madrid facilities.

Q PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY CONCLUSIONS.

A While certain aspects of the criticism by Mr. Michels and Ms. Kliethermes of my direct testimony ANEC impact estimate are valid, even when (i) my ANEC impact estimate is adjusted to reasonably respond to those specific criticisms and (ii) MISO market settlement and other MISO load-based charges are added in (which should only be done if the small market price reduction from the shutdown of the Noranda New Madrid facilities is also incorporated), I still estimate a combined ANEC and MISO charge impact that is below the $30 per MWh in retail sales revenues that would be provided by Noranda under its rate proposal in this proceeding. Specifically, my revised ANEC impact estimate indicates Ameren Missouri's ANEC (plus its MISO load-based charges not included in ANEC) would decrease between $27.91 and $28.49 for every MWh that would have been sold to Noranda.

With respect to the use of forecasted market prices, they are speculative and generally should not be used in ratemaking. Furthermore, the Polar Vortex Anomaly event of this past winter has distorted the current level of these prices. For these reasons, the ANEC impact should be estimated based on three years of known historical market prices with severe abnormalities removed and any consistent known and measurable trend reflected. This is the approach I have used to develop my revised ANEC impact estimate. Furthermore, while the proposed Noranda rate plan of $30 per MWh provides for up to 2% rate increase for Noranda during each future Ameren Missouri base rate case over the 10-year term of the Noranda proposal, it is my understanding that the Commission is not precluded from reviewing the continued reasonableness of the Noranda rate in future Ameren Missouri rate proceedings.

With respect to the future resource needs of Ameren Missouri, Ameren Missouri is not currently projecting the need for any new generation resources during the 10-year period of Noranda's rate proposal. In fact, its last available projection, which it provided in 2013, is that Ameren Missouri will not need to add a major new generation facility until sometime after 2029. Furthermore, as I discuss in detail in this testimony, the continued operation of Ameren Missouri's existing generation facilities will be a function of market prices and the cost for environmental compliance, not the MW level of Ameren Missouri's load.

Finally, Ameren Missouri has in previous proceedings before the Commission raised concerns with increased transmission congestion costs if Noranda's New Madrid facilities were to be shut down. This increase in transmission congestion could increase costs for Ameren Missouri customers and Associated Electric Cooperatives, Inc. ("AECI") member system customers. It could also require these two utility systems to incur new capital expenditures on their respective transmission systems to address the increased transmission congestion. As a result, a shutdown of Noranda's New Madrid facilities could actually require Ameren Missouri to incur capital expenditures that it would not have otherwise had to incur.

My Schedule JRD-Surrebuttal-1 provides a high level summary of my revised ANEC impact estimate and Schedules JRD-Surrebuttal-2 and JRD-Surrebuttal-3 provide the underlying detail for that schedule. My revisions can be summarized as follows:

- I have updated the original core components of Ameren Missouri's ANEC that were included in my direct testimony estimate of $27.05 per MWh to reflect:
  - The AMMO.UE MISO pricing node rather than the AECI.AMMO pricing node;
  - The AECI 3.5% loss factor;
  - The use of normalized historical energy market prices for the most recent 36 month period with the Polar Vortex Anomaly removed;

- The effect of the estimated 1.5% reduction in energy market prices due to a shutdown of Noranda's load on the avoided cost of clearing the Noranda load in the MISO energy market; and
- The 2014-2015 MISO Planning Resource Auction capacity price of $16.75 per MW-day.

- I have expanded my ANEC impact estimate to include all of Ameren Missouri's material MISO market settlement charges and credits that are materially sensitive to the amount of load served by Ameren Missouri.
- I have expanded my ANEC impact estimate to include the impact of the estimated 1.5% reduction in energy market prices due to a shutdown of Noranda's load on Ameren Missouri's off-system energy sales revenues and purchased power costs.
- I have expanded my ANEC impact estimate to include the very small drop in Ameren Missouri's Schedule 26 regional transmission charges that would result from a shutdown of Noranda's load.
- I have added to my ANEC impact estimate the MISO administration charges that Ameren Missouri would avoid due to a shutdown of the Noranda load.

As I have noted, the net impact of all of the above adjustments is to raise my direct testimony estimate of Ameren Missouri's incremental cost savings from a shutdown of the Noranda load from $27.05 for every MWh that would have been sold to Noranda to a range of $27.91 to $28.49 for every MWh that would have been sold to Noranda. However, this revised ANEC and MISO administration cost savings estimate is still $1.51 per MWh to $2.09 per MWh lower than the $30 per MWh rate proposed by Noranda.

II. Response to Ameren Missouri Witness Matt Michels and Staff Witness Sarah Kliethermes

Q ON A HIGH LEVEL, PLEASE BRIEFLY SUMMARIZE MR. MICHELS' AND MS. KLIETHERMES' CRITICISMS OF YOUR $27.05 PER MWH DIRECT TESTIMONY ESTIMATE ON THE IMPACT ON AMEREN MISSOURI'S ANEC IF THE NORANDA NEW MADRID FACILITIES WERE TO SHUT DOWN.

A On a high level, Mr. Michels' and Ms. Kliethermes' criticisms are as follows:

- Mr. Michels testifies that my direct testimony ANEC impact estimate should have been calculated at the AMMO.UE MISO CPNode not the AECI.AMMO CPNode. Ms. Kliethermes proposes to calculate the ANEC impact estimate[1] at the AMMO.TS1, AMMO.OSAGE1 and AMMO.RUSHIS1 CPNodes rather than the AECI.AMMO CPNode.

- Mr. Michels argues that the 12-month historical period ending October 31, 2013 that I used for energy market prices in my ANEC impact estimate was too narrow and out of date for purposes of estimating the ANEC impact. Ms. Kliethermes proposes to use the 48-month historical period ending March 31, 2014 or the 12-month historical period ending April 1, 2014.

- Both Mr. Michels and Ms. Kliethermes propose to replace the $1.05 per MW-day capacity market price that I utilized in my direct testimony ANEC impact estimate with the more recent MISO capacity market price of $16.75 per MW-day.

- Mr. Michels indicates that my direct testimony ANEC impact estimate failed to include Associated Electric Cooperatives, Inc. ("AECI") losses of 3.5% from the MISO border with AECI to Noranda's meter. Ms. Kliethermes also proposes to apply the 3.5% AECI loss factor in the ANEC impact estimate.

- Mr. Michels argues that my direct testimony ANEC impact estimate failed to include certain MISO settlement charges (including ancillary service charges), MISO Schedule 26 transmission charges and other MISO load-based charges. Ms. Kliethermes also advocates the inclusion of additional MISO charges in the ANEC impact estimate.

- Mr. Michels' argues that my ANEC impact estimate should have considered the current forecasted market prices for energy and capacity over the 10-year period of the Noranda proposal.

[1]Ms. Kliethermes in her testimony refers to the change in the ANEC as "Ameren Missouri's wholesale energy cost of providing service to Noranda." I disagree with her characterization. The reduction in Ameren Missouri's ANEC from a shutdown of the Noranda New Madrid facilities is the incremental net fuel and purchased power cost that is avoided by Ameren Missouri by not having to clear the Noranda load in the MISO energy, operating reserve and capacity markets. It is not Ameren Missouri's wholesale energy cost for serving Noranda.

- Mr. Michels argues that Ameren Missouri could experience savings in future generation resource capital expenditures from a Noranda shutdown.

Q IN GENERAL, HOW DO YOU RESPOND TO THESE CRITICISMS?

A Certain portions of these criticisms are valid and warrant revision to my direct testimony ANEC impact estimate. However, the balance of the criticisms, especially those that rely on current forecasted market price information that has been distorted by the Polar Vortex Anomaly of this past winter, are unwarranted. Furthermore, as I have noted, even when I revise my direct testimony ANEC impact estimate to reasonably address those portions of Mr. Michels' and Ms. Kliethermes' criticisms that are valid, I still end up with an estimated total cost savings impact of less than $30 per MWh.

A. MISO Pricing Node

Q HOW DO YOU SPECIFICALLY RESPOND TO MR. MICHELS' CRITICISM OF YOUR USE OF THE AECI.AMMO CPNODE IN YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE RATHER THAN THE AMMO.UE CPNODE?

A At the time of preparing my direct testimony, I did not know with certainty whether Ameren Missouri clears the Noranda load in the MISO market at AMMO.UE or some other MISO pricing node. This was an issue of concern because the Noranda load is physically interconnected to the AECI transmission system rather than directly interconnected to the Ameren Missouri transmission system. Due to this uncertainty and to be conservative in my estimate, I chose the higher priced of the two nodes that I considered to be most likely to be the location where Ameren Missouri clears the Noranda load in the MISO market – AECI.AMMO.

In response to discovery, which was not available in this proceeding when my direct testimony was prepared, and in Mr. Michels' rebuttal testimony, Ameren Missouri has provided certainty with respect to the pricing node where Noranda's load is cleared by Ameren Missouri in the MISO market – AMMO.UE. As a result, I agree with Mr. Michels that my direct testimony ANEC impact estimate should be revised to use AMMO.UE historic prices rather than AECI.AMMO historic prices. I have included this change in the revised ANEC impact estimate that I present in Schedules JRD-Surrebuttal-1, JRD-Surrebuttal-2 and JRD-Surrebuttal-3.

Q HOW DO YOU RESPOND TO MS. KLIETHERMES' POSITION THAT THE AMMO.TS1, AMMO.OSAGE1 AND AMMO.RUSHIS1 CPNODES SHOULD BE USED?

A In response to Data Request Noranda 1.2 to Staff, Ms. Kliethermes indicated that she was in error in using those three generation pricing nodes in her direct testimony and now agrees it would be more appropriate to use the AMMO.UE CPNode for the ANEC impact estimate.[2]

B. Historic Period for Energy Market Prices

Q PLEASE EXPLAIN YOUR SELECTION OF THE 12 MONTHS ENDING OCTOBER 31, 2013 FOR THE HISTORIC ENERGY MARKET PRICES YOU USED IN YOUR DIRECT TESTIMONY ANEC IMPACT ANALYSIS.

A I selected the most recent 12 month period available when I performed the calculation for my direct testimony in November of 2013. I did not revise it prior to filing my direct

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[2]Schedule JRD-Surrebuttal-12 contains a complete copy of all data request responses that I cite to in this testimony.

testimony because nothing had fundamentally changed in the market between the performance of the calculation and the filing of my direct testimony.

After considering some of the points made by Mr. Michels and Ms. Kliethermes, I believe it is reasonable to normalize the historic energy market prices being utilized in my ANEC impact estimate in a manner that is generally consistent with the way this has been done in recent years for the determination of Ameren Missouri's Net Base Energy Cost ("NBEC") in Ameren Missouri's base rate proceedings.[3] Specifically, 36 months of historic energy market prices should be averaged with severe market anomalies removed and any known and measurable long-term trends reflected. I propose to use: (i) the 36 month period ending December 31, 2013 with no adjustments, or (ii) alternatively, the period of the 36 months ending April 30, 2014, with January through March energy market prices from 2014 (the period of the Polar Vortex Anomaly), replaced with the average of energy market prices from January through March of 2012 and 2013.

The 36-month period ending December 31, 2013 averages to an around-the-clock day-ahead hourly market price of $27.26 per MWh at the AMMO.UE pricing node. The 36-month period ending April 30, 2014, with January through March of 2014 prices replaced with the average of January through March prices from 2012 and 2013, averages to an around-the-clock day-ahead hourly market price of $26.69 per MWh at the AMMO.UE pricing node. I have used both of these alternative measures of normalized historical market prices in the revised ANEC estimate that I present in Schedules JRD-Surrebuttal-1, JRD-Surrebuttal-2 and JRD-Surrebuttal-3.

[3]NBEC is the baseline value of fuel and purchased power costs reduced by off-system sales revenues to which Ameren Missouri's ANEC is compared in Ameren Missouri's FAC.

Q MR. MICHELS OFFERS AN UPDATED HISTORICAL PERIOD OF THE 12 MONTHS ENDING APRIL 30, 2014 (MICHELS REBUTTAL AT 19). MS. KLIETHERMES OFFERS THE HISTORICAL PERIODS OF THE 48 MONTHS ENDING MARCH 31, 2014 OR THE 12 MONTHS ENDING APRIL 1, 2014 (KLIETHERMES REBUTTAL AT 8-9). ARE ANY OF THESE HISTORIC PERIODS REASONABLE TO USE FOR THE ANEC IMPACT ESTIMATE?

A No. First, Mr. Michels himself agrees that a 12-month period is too narrow (Michels Rebuttal at 12). Second, all three of these proposals would include the Polar Vortex Anomaly period of January through March 2014 with no downward adjustments to remove the market anomaly. Finally, while Ms. Kliethermes' use of a 48 months historic period could be viewed as an attempt to try average out the Polar Vortex Anomaly, it fails to do so because the 48 month average in effect assumes a Polar Vortex Anomaly event will repeat every four years (i.e., every 48 months).

C. Normalization of Historic Energy Market Prices in Past Ameren Missouri Base Rate Proceedings

Q IN PAST RATE PROCEEDINGS, HAS AMEREN MISSOURI PROPOSED TO USE THE AVERAGE OF HISTORIC MARKET PRICES WITH SEVERE ANOMALIES REMOVED TO DETERMINE ITS NBEC?

A Yes. In all of its base rate proceedings before the Commission since the start of operation of the MISO energy market in 2005, Ameren Missouri in one form or another has proposed to use normalized historic energy market prices to determine the NBEC portion of its base rate revenue requirement.

In Case No. ER-2007-0002, Ameren Missouri proposed to use an average of 36 months of historic energy market prices from January 2003 through December of 2005, with downward adjustments to remove certain severe market anomalies in

2005 (Ameren Missouri witness Schukar Direct in Case No. ER-2007-0002 at 8-9). Specifically, Ameren Missouri made downward market price adjustments to remove the effects of: (i) abnormally high on-peak historic market prices over the period of August through December of 2005 due to Hurricanes Dennis, Katrina and Rita and (ii) abnormally high off-peak historic market prices over the period of July through December of 2005 due to rail transportation disruptions (*Id.* at 12-16). As Mr. Schukar indicated in his rebuttal testimony in that proceeding:

> "Taking a simple three-year average does not address these market disruptions, because the averaging will only help to average out *normal* volatility that occurs in any given year. It will not address the *abnormal* impact that occurs as a result of extraordinary events like the 2005 hurricanes or the rail disruptions."

and

> "[T]hese types of events had an extraordinary impact on market conditions that cannot be expected to occur every couple years – which means taking the three-year average without further adjustments cannot be used to 'normalize' market conditions."

(Schukar Rebuttal in Case No. ER-2007-0002 at 4)

In Case No. ER-2008-0318, Ameren Missouri proposed to perform an average of 24 months of historic energy market prices from January 2006 through December 2007, with no downward adjustments (Ameren Missouri witness Schukar Direct in Case No. ER-2008-0318 at 10-12). However, Mr. Schukar made clear in his direct testimony in that proceeding that he did not propose to use more than 24 months of data because, in his opinion, market conditions prior to 2006 were unusually high and not representative of normalized market conditions, particularly "... in 2005, when disruptions in coal transportation, the effects of Hurricanes Dennis and Katrina, and the start-up of the MISO energy markets created highly unusual market conditions" (*Id.* at 13). Thus, Ameren Missouri's proposal in Case No. ER-2008-0318 was effectively to use the average of 36 months of historical prices ending December 31, 2007, but with the 12 month period of January 2005 through December of 2005 removed from the average due to it being anomalous.

In Case Nos. ER-2010-0036, ER-2011-0028 and ER-2012-0166, Ameren Missouri proposed to average 36 months of historic energy market prices at the end of the applicable true-up period, with no adjustments for severe market anomalies. However, it was important to note that no severe market anomalies were identified in those proceedings by Ameren Missouri (or any other party) for the 36-month historic periods considered in each of those three cases.

Q **DID STAFF OFFER AN OPINION WITH REGARD TO REMOVING SEVERE MARKET ABNORMALITIES IN THESE PREVIOUS PROCEEDINGS?**

A Yes. For example, in his direct testimony in Case No. ER-2007-0002, Staff witness Dr. Michael Proctor noted the rail transportation and hurricane market anomalies of 2005 and indicated:

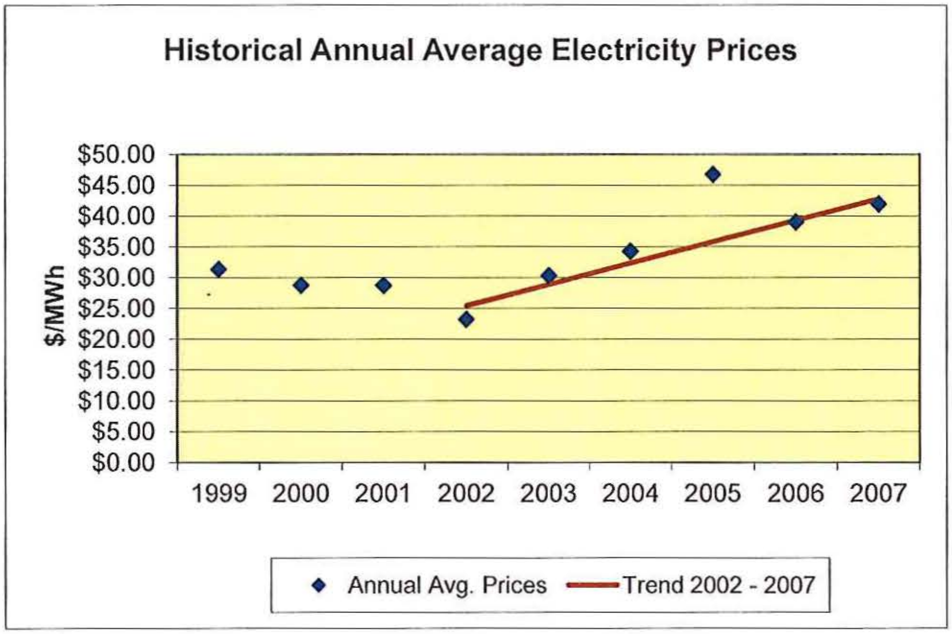
> "The objective of my analyses is to remove the effects of these abnormal events on prices and recommend a set of normal prices to be used in this rate case."

(Staff witness Proctor Direct in Case No. ER-2007-0002 at 3).

Q YOU INDICATED IN YOUR DIRECT TESTIMONY THAT YOU HAVE PREVIOUSLY TESTIFIED IN EACH OF THESE PREVIOUS AMEREN MISSOURI BASE RATE PROCEEDINGS WITH RESPECT TO AMEREN MISSOURI'S FUEL COSTS, PURCHASED POWER COSTS AND OFF-SYSTEM SALES REVENUES (DAUPHINAIS DIRECT AT 1-2). WHAT POSITION HAVE YOU TAKEN WITH RESPECT TO THE HISTORICAL ENERGY MARKET PRICE NORMALIZATION APPROACH?

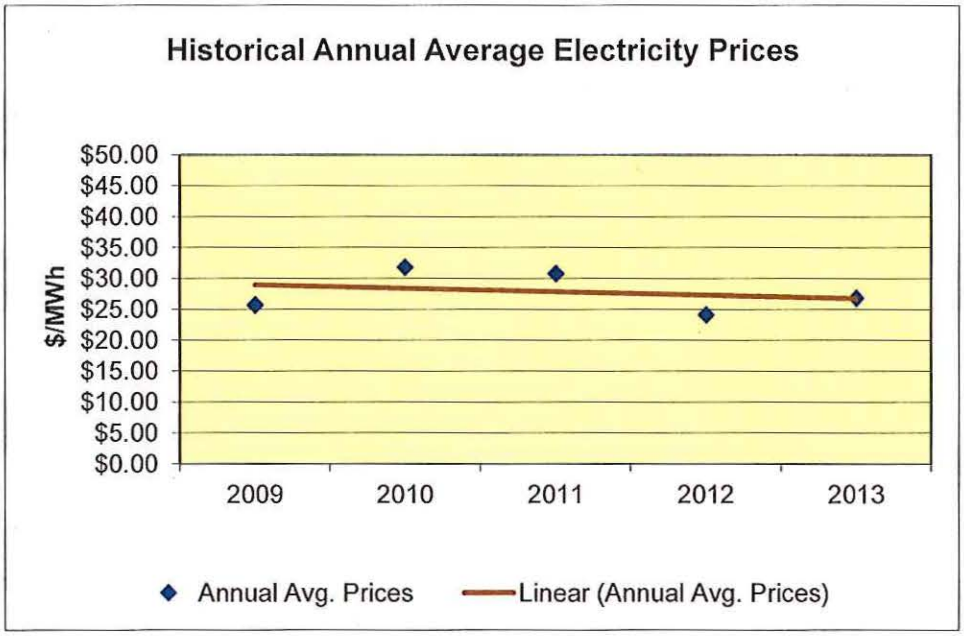
A I have generally not opposed the averaging of 36 months of historical hourly energy market prices with severe market anomalies removed <u>provided any known and measurable historic trend in those prices is incorporated into the final normalized results</u> (e.g., Dauphinais Direct in Case No. ER-2007-0002 at 7-11). In Ameren Missouri Case Nos. ER-2007-0002 and ER-2008-0318, there had been a consistent ongoing escalation trend in historic energy market prices for several years in a row as shown in Figure JRD-1 below (previously presented as Figure JRD-3 of my Surrebuttal Testimony in Case No. ER-2008-0318 and in Staff witness Michael Proctor's testimony in that proceeding).

Figure JRD-1



As a result, I opposed using averages of historical market prices, with or without anomalies removed, unless the ongoing escalation trend in market prices was also reflected (e.g., by only using the most recent 12 of the 36 months in the average). However, in later cases, specifically, Case Nos. ER-2010-0036, ER-2011-0028 and ER-2012-0166, as shown in Figure JRD-2 below, the previous consistent upward trend in natural gas and electric energy market prices that had been previously present from 2002 through 2008 had ended. This end in the previous trend is the result of the fracking and horizontal drilling revolution in the natural gas industry.

Figure JRD-2



Due to the end of the previous known and measurable upward price trend, I did not suggest incorporating a trend adjustment to averaged historic energy market prices in these three most recent Ameren Missouri base rate cases. For the same reason, I have not proposed a trend adjustment in this current proceeding to averaged historic energy market prices.

D. *The Polar Vortex Anomaly*

Q **PLEASE DESCRIBE THE POLAR VORTEX ANOMALY AND YOUR BASIS OF NOT INCLUDING THE PERIOD DURING WHICH IT OCCURRED IN YOUR 36 MONTHS OF AVERAGED HISTORICAL HOURLY ENERGY PRICES IN THIS PROCEEDING.**

A The "Polar Vortex Anomaly" is the term I use to refer to the period of extreme cold temperature events that occurred during the months of January, February and March of 2014. During this period, the coldest temperatures seen in many years were experienced in the Midwest, Mid-Atlantic, South Central and Southeast United States. For example, the National Weather Service reported that Chicago had the coldest weather on record since 1872 for the period of December through March (National Weather Service Public Information Statement, April 1, 2014, 9:37 AM CDT, attached as Schedule JRD-Surrebuttal-9).

Furthermore, MISO, in its April 1, 2014 presentation to the Federal Energy Regulatory Commission ("FERC") in *Winter 2013-2014 Operations and Market Performance in RTOs and ISOs,* Docket No. AD14-8-000 reported extreme low temperatures were experienced across the entire MISO Region and temperatures in many areas were the coldest in 20 years.[4] MISO's presentation also indicated numerous days from January through March of 2014 on a MISO system wide basis that were well below average hourly low temperatures for the same days in 2012 and 2013 and well below monthly average low temperatures from the past six years. (*Winter 2013-2014 Operations and Market Performance*, Richard Doying, Midcontinent Independent System Operator, April 1, 2014 at Slide 3, attached as Schedule JRD-Surrebuttal-10.)

Also, the FERC Staff's presentation during the same technical conference on April 1, 2014 in Docket No. AD14-8-000 showed the wide geographical breadth of several of the extreme cold weather events that took place (*Winter 2013-2014 Operations and Market Performance in RTOs and ISOs*, FERC Staff, April 1, 2014 at Slide 2, attached as Schedule JRD-Surrebuttal-11).

These extremely low temperatures led to very high natural gas and electricity demand, as well as non-firm natural gas disruptions, coal pile freeze ups and other

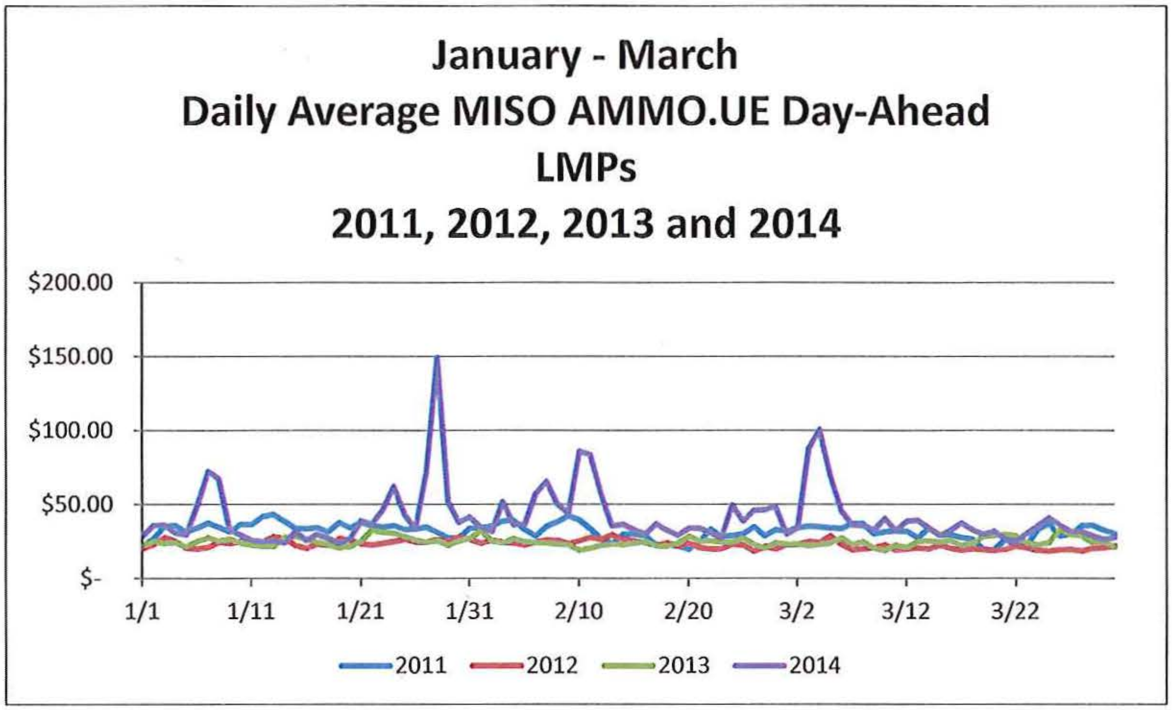
[4]The MISO Region stretches from Montana to Michigan and from Manitoba to Louisiana.

forced generation derates and outages. All of this elevated hourly day-ahead and real-time electricity market prices to astronomical levels that have not been seen in the Midwest since the late 1990s.

The FERC Staff presentation from Docket No. AD14-8-000 shows that national natural gas demand soared above five-year averages on several occasions from January through March of 2014 and peak natural gas demand in the Northeast and Southeast coincided (Schedule JRD-Surrebuttal-11 at Slides 3 and 4). The FERC Staff presentation also shows that new winter peak electricity demands were set in MISO and the adjacent PJM and SPP Regional Transmission Organizations ("RTO") (*Id.* at Slide 6). Additionally, the FERC Staff presentation shows the impact of this soaring natural gas demand on spot natural gas prices, especially in the Northeast, but also as far west as Chicago Citygates (*Id.* at Slide 5). The MISO presentation in Docket No. AD14-8-000 shows the extent of forced generation outages within MISO for select days from January through March of 2014 that resulted from scarce, high priced natural gas and the freeze up of generation components (Schedule JRD-Surrebuttal-10 at Slide 4). As can be seen from this slide, MISO generation outage levels were well above 2013 levels.

Figure JRD-3 below shows the impact all of this had on daily averaged MISO day-ahead hourly energy market prices at the AMMO.UE pricing node for the January through March period for 2014 versus that for the same period in 2011, 2012 and 2013. As can be seen, average day-ahead market prices for 2014 for January through March were much higher and much more volatile than they were in 2011, 2012 and 2013 illustrating the anomalous nature of January through March of 2014.

Figure JRD-3



The extreme cold weather event of this past January through March is a severe market anomaly much like the one that followed Hurricanes Katrina and Rita in 2005. As I noted earlier, Ameren Missouri made downward market price adjustments for the Hurricanes Katrina and Rita market anomaly in Case Nos. ER-2007-0002 and ER-2008-0318.

Figure JRD-4 below shows averaged hourly day-ahead energy prices at the AMMO.UE pricing node for the periods of January through March and September through December from the April 1, 2005 start of the MISO energy market. Hurricane Katrina made landfall on August 29, 2005 and Hurricane Rita on September 24, 2005.

Figure JRD-4

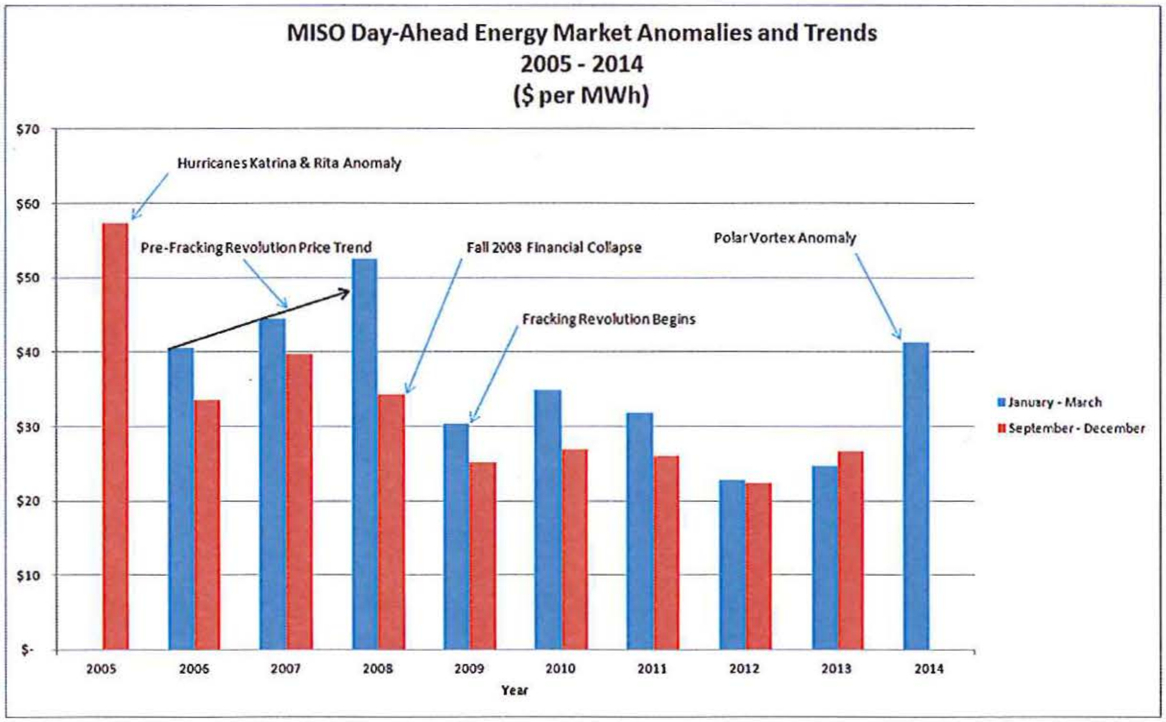


Figure JRD-4 shows the abnormally high market prices that resulted in the four months immediately following the first of the two Hurricanes (September through December of 2005). The figure also shows this market anomaly largely dissipated during the immediately following January through March of 2006 period, was completely gone by September through December of 2006 and has not subsequently repeated itself. The figure also clearly shows several other market characteristics of the past 10 years including: (i) the persistent year-to-year escalation in spot energy prices that denoted the pre-fracking revolution period of 2002 through 2008, (ii) the financial collapse of 2008, and (iii) the start of the fracking revolution in natural gas that continues to this day. Finally, the figure shows the January through March 2014 Polar Vortex Anomaly and provides another perspective with respect to its magnitude on a three-month average basis versus market prices for the same three months in the preceding five years. Short of another severe market anomaly occurring in the next few months, there is no compelling reason to believe that the impact of the Polar Vortex Anomaly on spot energy market prices will not quickly dissipate just like with the Hurricanes Katrina and Rita Anomaly as shown above.

E. *Capacity Prices*

Q MR. MICHELS HAS CRITICIZED YOUR USE OF A SINGLE HISTORIC VALUE FOR THE CAPACITY MARKET PRICE FOR YOUR ANEC IMPACT ESTIMATE WHILE MS. KLIETHERMES PROPOSES TO USE A MORE RECENT MISO CAPACITY MARKET PRICE. HOW DO YOU RESPOND?

A Prior to the start of the MISO capacity market in June of 2013, there was no reliable source for market prices available within MISO for capacity. The capacity market was purely bilateral and these bilateral transactions in a number of cases included an energy delivery component at a specified energy price. Furthermore, unlike for the bilateral energy market, the industry did not maintain market price indices reflecting surveys of the market prices that market participants were paying for capacity. In light of all of this, the only reliable source for capacity prices within MISO available to me prior to the filing of my direct testimony was MISO's 2013-2014 Planning Resource Auction ("PRA") result for Local Resource Zone 5 -- the Local Resource Zone in which Ameren Missouri is located.

On April 15, 2014, over two months after I filed my direct testimony in this proceeding, MISO released the results of its second PRA -- this time for the period of June 1, 2014 through May 31, 2015. Mr. Michels is correct in that this new capacity market price, $16.75 per MW-day, is much higher than this past year's price of $1.05 per MW-day. However, this is not necessarily indicative of steeply rising capacity market prices in the near future but rather a reflection that the 2013-2014 PRA result was extremely low. As such, I do not propose to average the 2014-2015 PRA capacity price with the very low 2013-2014 PRA capacity price. Instead, in my revised ANEC impact estimate presented in Schedules JRD-Surrebuttal-1, JRD-Surrebuttal-2 and JRD-Surrebuttal-3, I utilize the much higher 2014-2015 MISO PRA capacity market price of $16.75 per MW-day as is. This is the same capacity market price that Ms. Kliethermes proposes to use (Kliethermes Rebuttal at 9).

Q THIS SOUNDS LIKE A LARGE INCREASE, TO PLACE IT INTO PERSPECTIVE, HOW MUCH DOES THE INCREASE AFFECT THE ANEC IMPACT ESTIMATE?

A It amounts to an increase of $0.76 per MWh.

F. AECI Losses

Q HOW DO YOU RESPOND TO MR. MICHELS' CRITICISM WITH RESPECT TO NOT REFLECTING AECI LOSSES IN YOUR ANEC IMPACT ESTIMATE AND MS. KLIETHERMES' PROPOSAL TO APPLY THOSE LOSSES TO THE ANEC IMPACT ESTIMATE?

A They are correct in that AECI losses should have been incorporated into my direct testimony ANEC impact estimate since the proposed rate for Noranda does not include a separate charge to collect the cost for AECI losses. I have applied the 3.5% AECI loss factor in my revised ANEC impact calculation that I present in Schedules JRD-Surrebuttal-1, JRD-Surrebuttal-2 and JRD-Surrebuttal-3.

G. *MISO Market Settlement Charges (Including Ancillary Service and Uplift Charges), MISO Regional Transmission Charges and other MISO Load-Based Charges*

Q **HOW DO YOU RESPOND TO MR. MICHELS' CRITICISM WITH RESPECT TO NOT INCLUDING AVOIDED MISO MARKET SETTLEMENT CHARGES (INCLUDING ANCILLARY SERVICE CHARGES AND UPLIFT CHARGES), CERTAIN MISO REGIONAL TRANSMISSION CHARGES AND OTHER MISO LOAD-BASED CHARGES IN YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE (MICHELS REBUTTAL AT 15-16) AND MS. KLIETHERMES PROPOSAL TO INCLUDE SUCH ADDITIONAL CHARGES IN THE ANEC IMPACT ESTIMATE (KLIETHERMES REBUTTAL AT 9)?**

A I did not include MISO market settlement charges (including ancillary service charges and uplift charges) for two reasons. First, as I noted at the bottom of Schedule JRD-2 of my direct testimony, the MISO market settlement charges generally net to a relatively small number. Second, I had conservatively assumed in my direct testimony ANEC impact estimate that MISO market prices would not drop by <u>any</u> amount due to the shutdown of Noranda's New Madrid facilities. In fact, as I discussed in my direct testimony, MISO market prices for energy will drop by some small amount (Dauphinais Direct at 9-10). This amount will not necessarily be enough to significantly change the dispatch of Ameren Missouri's generation facilities by MISO, but it would be enough to have some downward impact on the price of Ameren Missouri's off-system energy sales revenues and purchased energy costs. Therefore, if the analysis is expanded in detail to include net MISO market settlement charge savings from a shutdown of Noranda (as Mr. Michels has done), an estimate of the impact of the small drop in energy market prices should also be incorporated.

With respect to MISO regional transmission charges, Ameren Missouri is only subject to MISO regional transmission service charges on the basis of load under MISO Schedules 26 and 26-A. I included the estimated change in Ameren Missouri's MISO Schedule 26-A charges in my direct testimony ANEC impact estimate (see Schedule JRD-2). I did exclude MISO Schedule 26 charges, but only did so for the reason I noted on the bottom of my direct testimony Schedule JRD-2 – MISO Schedule 26 charges would not likely be significantly reduced for Ameren Missouri from a shutdown of Noranda's New Madrid facilities.

I did not include other MISO load-based charges for the same reason I did not include MISO Market Settlement charges – they are relatively small and should not be considered unless the impact form the small drop in energy market prices that would result from a shutdown of Noranda's New Madrid facilities is also considered. In addition, it should be noted that these other load-based MISO charges consist of administration charges that are not part of Ameren Missouri's ANEC and, as a result, are base rate costs that are not recoverable through Ameren Missouri's FAC. So, while they are costs that would be reduced for Ameren Missouri by a shutdown of Noranda's New Madrid facilities, the reduction in costs would only be seen through base rates and not through a reduction in Ameren Missouri's ANEC.

Q **IN HIS REBUTTAL TESTIMONY, MR. MICHELS PRESENTS AN ESTIMATE OF $0.40 PER MWH FOR THESE SO CALLED "OMITTED MISO CHARGES" (MICHAELS REBUTTAL AT 13). HAVE YOU REVIEWED HIS ESTIMATE?**

A Yes. As Ameren Missouri itself has admitted in response to Data Request Noranda 4-27, Mr. Michel's direct testimony estimate $0.40 per MWh includes errors and is missing a number of MISO market settlement and administration items whose amounts are sensitive to the amount of load that is served by Ameren Missouri.

For example, Ameren Missouri admits to miscalculating and, as a result, overstating the sensitivity of its MISO Schedule 26 regional transmission charges to a reduction in Ameren Missouri's load (Ameren Missouri Response to Data Request 4-27 j). Ameren Missouri also admits to not including its MISO Real-Time Distribution of Losses Amount in its $0.40 per MWh calculation.[5] The MISO Real-Time Distribution of Losses Amount is a significant credit against other MISO market settlement, transmission and administration charges that would diminish in value for Ameren Missouri if Noranda's New Madrid facilities were shut down (Ameren Missouri Response to Data Request 4-27 c, d and e).

Finally, Ameren did not include another load-sensitive MISO market settlement item that is also a sizable credit -- its MISO Auction Revenue Rights ("ARR") Stage 2 Distribution Amount.[6] It did so despite admitting in discovery that the combined total MW of Auction Revenue Rights ("ARR") (including ARR Stage 2 entitlements) that are allocated to it by MISO for the network transmission service Ameren Missouri receives from MISO is based on the peak demand of Ameren Missouri's load (Ameren Missouri Response to Data Request 4-27 f). In summary, Mr. Michels' rebuttal testimony estimate of MISO market settlement, transmission and administration charges beyond those I included in my direct testimony ANEC impact

[5]The MISO Real-Time Distribution of Losses Amount essentially pays back to Load Serving Entities such as Ameren Missouri the marginal loss charges that MISO collects through energy market prices that are in excess of MISO's actual cost to provide real power losses.

[6]The MISO ARR Stage 2 Distribution Amount pays out to network transmission customers such as Ameren Missouri the annual Financial Transmission Right ("FTR") auction revenues that MISO collects in excess of those auction revenues due to holders of Stage 1A, Restoration, Unterminated LTTR and Stage 1B ARRs. ARR Stage 2 payments are made by MISO in direct proportion to the difference between the network transmission customer's forecasted annual non-coincident peak demand and the total of that customer's Stage 1A, Restoration, Unterminated LTTR and Stage 1B ARRs.

estimate contains significant errors and overstates the net magnitude of those additional MISO charges.

Q **DID MS. KLIETHERMES IN HER REBUTTAL TESTIMONY INCLUDE AN ESTIMATE FOR ADDITIONAL MISO SETTLEMENT, TRANSMISSION AND ADMINISTRATION CHARGES?**

A Yes. She includes a public estimate and a highly confidential estimate. Her public estimate is that the additional MISO charges (ancillary service and uplift) amount to $0.44 per MWh (Kliethermes Schedule SLK 3 – Energy). Her highly confidential estimate is that these additional MISO charges amount to **Highly Confidential Information Removed** per MWh (Kliethermes Schedule SLK 5 HC Impact). Both of her calculations are flawed and overstate the actual amount.

For her public estimate, she bases her numbers on what appears to be the average market wide cost for ancillary services and uplift per MWh of load as reported by the MISO Independent Market Monitor ("IMM") from March 2013 through February 2014 (Kliethermes Workpapers at "NP Other Charges"). While these are useful metrics for evaluating the overall performance of the MISO market with respect to these two types of costs, these are not the specific ancillary service and uplift charges that Ameren Missouri is subject. For example, MISO Voltage and Local Reliability ("VLR")-related uplift charges are directly assigned to the load in the Local Balancing Area ("LBA") where VLR issues exist – they are not uplifted to all load within MISO.

In addition, Ameren Missouri's MISO ancillary service charges and uplift charges are offset by significant MISO credits -- MISO Distribution of Losses of Amounts and MISO ARR Stage 2 Distribution Amounts. Ms. Kliethermes has not included these offsets in her public estimate of additional MISO charges. As a result, her public estimate is not correct and overstates the additional load-sensitive net MISO settlement, transmission and administration charges that were not included in my direct testimony ANEC impact estimate.

There are also flaws with her highly confidential estimate. For example, she includes a so called average transmission charge for one MWh of energy in the Ameren Missouri load zone that she drew on from Ameren Missouri's response to Data Request MPSC 0006 (Kliethermes Workpapers at "HC AMMO"). However, the magnitude of that average transmission charge is such that it must include Ameren Missouri's MISO Schedule 26 transmission service charges – charges that are largely <u>not</u> sensitive to the amount of load served by Ameren Missouri and as a result will not be significantly reduced for Ameren Missouri by a shutdown of Noranda's New Madrid facilities.

In addition, like with Mr. Michels' estimate, her highly confidential estimate only includes a subset of the MISO market settlement, transmission and administration charges and credits that Ameren Missouri settles with MISO that are sensitive to the amount of load which is served by Ameren Missouri. In particular, like with Mr. Michels' estimate and her public estimate, her highly confidential estimate neglects to include the two large MISO credits that I previously mentioned that Ameren Missouri receives which are sensitive to the amount of load that Ameren Missouri serves – Real-time Distribution of Losses Amounts and ARR Stage 2 Distribution Amounts. As a result, Ms. Kliethermes' highly confidential estimate, like her public estimate and Mr. Michel's estimate, is not correct and overstates the additional load-sensitive net MISO market settlement, transmission and administration charges that were not included in my direct testimony ANEC impact estimate.

Q PLEASE IDENTIFY ALL OF THE MATERIAL MISO MARKET SETTLEMENT, TRANSMISSION AND ADMINISTRATION CHARGES AND CREDITS THAT WERE NOT INCLUDED IN YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE AND ARE MATERIALLY AFFECTED BY THE AMOUNT OF LOAD THAT AMEREN MISSOURI SERVES.

A In Table JRD-1 below I present each of the material Ameren Missouri MISO market settlement, transmission and administration credits and changes that I did not include in my direct testimony ANEC impact estimate and are materially sensitive to the amount off load that Ameren Missouri serves. In the table, I note which of the items are part of Ameren Missouri's ANEC and which are not. The items included in Ameren Missouri's ANEC are MISO market settlement charges and credits. The other items are MISO administration charges that are only recoverable in Ameren Missouri's base rates. I also denote in the table which of the items were included in the rebuttal testimony estimate of Mr. Michels and the highly sensitive rebuttal testimony estimate of Ms. Kliethermes. As can be seen, neither Mr. Michels nor Ms. Kliethermes has included all of these items in their respective estimates of additional load-sensitive MISO market settlement, transmission and administration charges and credits.

Table JRD-1

Material Ameren Missouri MISO Market Settlement, Transmission and Administration Items Materially Sensitive to the Amount of Load Served by Ameren Missouri (excluding Energy settlements, Capacity settlements and MISO Schedule 26-A Charges)			
Item	Part of ANEC	Michels Rebuttal	Kliethermes Highly Sensitive Rebuttal
DA RSG Distribution Amount	Yes	No	No
RT Distribution of Losses Amount (credit)	Yes	No	No
RT Miscellaneous Amount	Yes	No	No
RT Net Inadvertent Amount	Yes	Yes	No
RT Revenue Neutrality Uplift Amount	Yes	No	Yes
RT RSG First Pass Distribution Amount	Yes	No	No
RT Regulation Cost Distribution Amount	Yes	Yes	Yes
RT Spinning Reserve Cost Distribution Amount	Yes	Yes	Yes
RT Supplemental Reserve Cost Distribution Amount	Yes	Yes	Yes
ARR Stage 2 Distribution Amount (credit)	Yes	No	No
MISO Market Administration Charges (MISO Schedule 17)	No	Yes	Yes
MISO Schedule 24 Allocation Amount	No	Yes	Yes
MISO Schedule 10 Transmission Administration Charge	No	No	Yes
MISO Schedule 10-FERC (FERC Assessment)	No	No	Yes

Q **IF THE DETAIL OF YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE IS EXPANDED TO INCLUDE ANY OF THE ITEMS IN TABLE JRD-1, SHOULD IT BE EXPANDED TO INCLUDE ALL OF THE ITEMS?**

A Yes, if any of the items are added all of them should be added as some are charges and others are credits. However, as I noted earlier, none of them should be added unless the detail of the estimate is also expanded to include the impact of the small reduction in energy market prices that would result from the shutdown of Noranda's New Madrid facilities.

Q **HAVE YOU ESTIMATED THE IMPACT OF A NORANDA SHUTDOWN ON ALL OF THESE MISO CHARGES AND CREDITS?**

A Yes. I have developed estimates for all of these MISO charges and credits.

In response to Data Request MPSC 0010, Ameren Missouri provided historical data on its actual day-ahead cleared load, actual real-time cleared load, and actual cleared amounts for each of the above MISO market settlement items for the past five years. For each of the MISO market settlements items (i.e., those items in Table JRD-1 that are included in Ameren Missouri's ANEC) except for ARR Day 2 Distribution Amounts, I calculated the annual amount per MWh of actual metered load for 2011, 2012 and 2013 to obtain the change in these amounts per MWh of load reduction as shown in Schedule JRD-Surrebuttal-4.

For ARR Day 2 Distribution Amounts, I took the total annual amount for this credit for Ameren Missouri for 2013 and divided it through an estimate of Ameren Missouri's Stage 2 ARR entitlement MW in order to obtain the change in Ameren Missouri's ARR Stage 2 Distribution Amount per MW-year of load reduction as shown in Schedule JRD-Surrebuttal-5.

In Schedules JRD-Surrebuttal-2 and JRD-Surrebuttal-3, I combined the per MW-year ARR Stage 2 Distribution Amount estimate and the per MWh estimate for the remaining MISO market settlement charges and credits to arrive at a net increase, rather than decrease, in Ameren Missouri's ANEC from these charges and credits of $0.18 for every MWh Ameren Missouri would have sold to Noranda.

With respect to the MISO administration charges in Table JRD-1 (i.e., the items in Table JRD-1 that are not included in Ameren Missouri's ANEC), except for MISO Schedule 24, I used MISO's latest posted rate for each charge. For MISO Schedule 24, I used Ameren's Missouri's actual 2013 MISO Schedule 24 Allocation Amount charges divided by Ameren Missouri's actual metered load for 2013 as shown in Schedule JRD-Surrebuttal-4. Summing all of these MISO administration charges together in Schedules JRD-Surrebuttal-2 and JRD Surrebuttal-3, I calculated Ameren Missouri would see a net decrease of its costs from these items of $0.31 for every MWh that it would have sold to Noranda. Combining this $0.31 per MWh MISO administration cost decrease with the $0.18 per MWh net MISO market settlement cost increase yields a net MISO cost decrease for Ameren Missouri from all of the items in Table JRD-1 of $0.13 for every MWh that Ameren Missouri would have sold to Noranda. This is far less of a decrease in this cost than was estimated by either Mr. Michels and Ms. Kliethermes. However, even then, it does not reflect the offsetting increase in its Ameren Missouri's ANEC that would result from the small reduction of energy market prices that would occur from a shutdown of Noranda's New Madrid facilities.

Q **PLEASE EXPLAIN WHY YOU HAVE NOT INCLUDED MISO SCHEDULE 26 REGIONAL TRANSMISSION CHARGES IN TABLE JRD-1.**

A I excluded them because, as I have noted, Ameren Missouri's MISO Schedule 26 transmission charges are not materially sensitive to the amount of load served by Ameren Missouri. This is true because under Schedule 26 the percent allocation of the cost of each MISO Schedule 26 transmission project to each transmission pricing zone in MISO is fixed at the time the transmission project is approved by MISO. As a result, the cost allocation under MISO Schedule 26 to each transmission pricing zone is unaffected by any future charge in the load in that transmission pricing zone. This means that, if an electric utility in a transmission pricing zone has a very high share of the total load in that transmission pricing zone (e.g., Ameren Missouri in MISO Transmission Pricing Zone 3B), the utility will see only a very small reduction in its Schedule 26 charges from the loss of a portion of its load (e.g., Noranda's load) because the loss of the load will not cause the MISO Schedule 26 revenue requirement allocated to the transmission pricing zone to go down.

Q **HAVE YOU QUANTIFIED THE VERY SMALL REDUCTION IN AMEREN MISSOURI'S SCHEDULE 26 CHARGES THAT WOULD RESULT FROM A SHUTDOWN OF NORANDA'S NEW MADRID FACILITIES?**

A Yes, I have done so in my Schedule JRD-Surrebuttal-6. In the schedule, I calculate the MISO Schedule 26 rate for MISO Transmission Pricing Zone 3B (the transmission pricing zone in which Ameren Missouri is located) with and without the Noranda load and Ameren Missouri's MISO Schedule 26 billing units with and without Noranda's load. In the schedule, I estimate Ameren Missouri's annual Schedule 26 charges to be \$11.081 million with Noranda's load and \$11.026 million without Noranda's load. So, the annual MISO Schedule 26 charge savings from a shutdown of Noranda would be less than \$60,000 or approximately \$0.01 for every MWh of sales that would have been made to Noranda. I have incorporated this very small value into my revised ANEC impact estimate that I present in Schedules JRD-Surrebuttal-1, JRD-Surrebuttal-2 and JRD-Surrebuttal-3.

Q **DOES AMEREN MISSOURI GENERALLY AGREE THAT ITS MISO SCHEDULE 26 CHARGES ARE NOT MATERIALLY SENSITIVE TO THE AMOUNT OF LOAD IT SERVES?**

A Yes, this appears to be the case. In its response to Data Request Noranda 4-27 j., Ameren Missouri identified a corrected annual Schedule 26 charge savings in the same neighborhood as the number I estimated above from publicly available data.

Q YOU HAVE INDICATED THAT YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE SHOULD NOT BE EXPANDED IN DETAIL TO INCORPORATE ANY OF THE MISO CHARGES AND CREDITS IN YOUR TABLE JRD-1 UNLESS THE ESTIMATE IS ALSO EXPANDED TO CAPTURE THE IMPACT OF THE SMALL REDUCTION IN ENERGY MARKET PRICES THAT WOULD RESULT FROM A SHUTDOWN OF NORANDA'S LOAD. HAVE YOU DEVELOPED AN ESTIMATE OF THE IMPACT OF THE SMALL REDUCTION IN ENERGY MARKET PRICES THAT WOULD RESULT FROM A SHUTDOWN OF NORANDA'S LOAD?

A Yes. I have developed a conservative estimate of the around-the-clock average expected percentage drop in energy market prices at the AMMO.UE pricing node for the shutdown of Noranda's load. I then applied this result in two ways. First, I used it to reduce the market price for the Net Energy, Transmission Loss and Congestion Cost that Ameren Missouri would directly avoid for not having to clear the Noranda load in the MISO energy market. Second, I reduced Ameren Missouri's average actual annual off-system energy sales revenues and purchased power expenses for 2011 through 2013 by my estimated average percentage drop in energy market prices that would result from the shutdown of the Noranda load. This captures the fact that a reduction in energy market prices would lower Ameren Energy's off-system energy sales and purchased energy cost roughly in direct proportion to the percentage drop in energy market prices.

Q PLEASE EXPLAIN HOW YOU ESTIMATED THE AVERAGE EXPECTED AROUND-THE-CLOCK DROP IN ENERGY MARKET PRICES AT THE AMMO.UE PRICING NODE FOR A SHUTDOWN OF NORANDA'S LOAD.

A I obtained from the MISO website historical hourly data on day-ahead energy market prices at the AMMO.UE pricing node and total MISO market load[7] for the 36 month period ending December 31, 2013. I then, for each hour, calculated the percent change in energy market prices from the previous hour per MW of load change from the previous hour. I then sorted this data from lowest to highest percentage per MW and determined the median and percentile ranks of the data that are presented in Schedule JRD-Surrebutal-7. The median from this analysis was an energy market price reduction of 1.76% for Noranda's average hourly load of 492.6 MW (4,314,915 MWh / 8,760 hour). I then had a linear regression of this data performed which yielded an energy market price reduction of 1.81% for Noranda's average hourly load of 492.6 MW. I then rounded these combined analytical results down to a 1.5% energy market price reduction to be conservative.

Q PLEASE EXPLAIN HOW YOU APPLIED THIS 1.5% ENERGY MARKET PRICE REDUCTION ESTIMATE TO YOUR ANEC IMPACT ESTIMATE.

A First, I added the line item titled "1.5% Market Price Reduction Impact on Net Energy Transmission Loss and Congestion Costs" as shown in Schedules JRD-Surrebuttal-2 and JRD-Surrebuttal-3 to capture the 1.5% lower market price at which Ameren Missouri would be able to sell the power it would have sold to Noranda into the MISO market. This reduced the ANEC savings to Ameren Missouri from a shutdown of

[7]MISO's Medium Term Load Forecast was used as a proxy for MISO's total day-ahead cleared market load.

Noranda's load by $0.41 to $0.42 for every MWh that would have been sold to Noranda.

Second, in Schedule JRD-Surrebuttal-8, I calculated an estimate of the decrease in off-system energy sales revenues and purchased power expenses for Ameren Missouri that would result from the energy market price reduction. I did this by first subtracting Ameren Missouri's average annual purchased power expense from 2011 through 2013 from its average annual off-system energy sales revenues from 2011 to 2013. I then multiplied these annual average off-system energy sales revenues less annual average purchased power expenses by 1.5% to estimate the net annual impact of the decrease in off-system energy sales revenues and purchased power costs for Ameren Missouri that would result from the market energy price decrease. In Schedule JRD-Surrebuttal-8, I calculated this to be a net annual decrease in Ameren Missouri's off-system energy sales revenues of $2,626,080. In other words, the small reduction in energy market prices due to a shutdown of Noranda would increase Ameren Missouri's ANEC by $2,626,080 annually due to reduced off-system energy revenues even after deducting the savings in Ameren Missouri's purchased power expenses that would result from the same reduction in energy market prices. As shown in my Schedules JRD-Surrebuttal-2 and JRD-Surrebuttal-3, this $2,626,080 annual amount translates to an ANEC increase for Ameren Missouri of $0.63 for every MWh that would have otherwise been sold to Noranda.

H. Forecasted Market Prices for Capacity and Energy

Q MR. MICHELS CRITICIZES YOUR DIRECT TESTIMONY ANEC IMPACT ESTIMATE BECAUSE IT DOES NOT CONSIDER FORECASTED MARKET PRICES FOR CAPACITY AND ENERGY FOR THE NEXT 10 YEARS INCLUDING CURRENT FORWARD MARKET PRICES FOR ENERGY (MICHELS REBUTTAL AT 23-38). HOW DO YOU RESPOND?

A First and foremost, while the Noranda rate proposal of $30 per MWh provides for up to 2% rate increase for Noranda during each future Ameren Missouri base rate case over the term, it is my understanding that the Commission is not precluded from reviewing the continued reasonableness of the Noranda rate in future Ameren Missouri rate proceedings before the Commission. Thus, if anything even remotely close to the horror story Mr. Michels tries to paint with forward market prices for energy and Ameren Missouri's own 10 year projection of the market price for capacity and energy were to develop in <u>actual</u> hourly MISO day-ahead market prices for energy and <u>actual</u> annual MISO market prices for capacity during the 10 year proposed term of the Noranda rate proposal, the Commission would have an ability to revisit the Noranda rate.

Second, neither forward market prices for energy nor Ameren Missouri's own projections for the market prices for energy and capacity over the next 10 years are known and measurable values that should be utilized in setting a rate.

Third, Ameren Missouri itself has opposed the use of forward market prices for energy to set the NBEC portion of its base rate revenue requirement. Furthermore, to the extent it has referenced forward market prices in those proceedings, it has focused on forward market prices on a rolling 12-month basis rather than forward market prices for delivery of power a few years into the future. In addition, it has not in any of those five base rate proceedings proposed to use its own long-term projections of future market prices for capacity and energy.

Fourth, the current forward market prices for energy are greatly distorted as part of the aftermath of the Polar Vortex Anomaly. As after the market anomaly associated with Hurricanes Katrina and Rita, it will take some time for forward market prices for energy to come down to more rational levels. Until that time, they should not be utilized at all in ratemaking other than to understand the degree of fear that is present in the current forward market for energy.

Q **YOU HAVE ASSERTED FORWARD MARKET PRICES FOR ENERGY AND AMEREN MISSOURI'S 10-YEAR PROJECTIONS OF MARKET PRICES FOR CAPACITY AND ENERGY ARE NOT KNOWN AND MEASURABLE VALUES AND SHOULD NOT BE USED TO SET RATES. PLEASE EXPLAIN WHY THESE VALUES SHOULD NOT BE CONSIDERED KNOWN AND MEASURABLE VALUES FOR RATEMAKING PURPOSES.**

These forward market prices and projections of market prices are not the prices at which Ameren Missouri will sell the power that it would have otherwise sold to Noranda. This power will instead be sold into the MISO day-ahead energy market, MISO annual PRA for capacity and/or the bilateral market for capacity. Forward market prices for energy at best represent the market consensus on a particular trading day of the spot market price for energy for a future delivery period at a specific delivery point. Thus, both forward market prices for energy and Ameren Missouri's own projections of the future market price of capacity and energy are only predictions of the future that may or may not come true. While it is appropriate to give some consideration in ratemaking to these predictions (e.g., with respect to whether they provide any anecdotal evidence in support of the continuation of upward or downward cost trends that are seen in historical prices), it is not reasonable to set rates on the basis of predictions especially when the Commission will have the ongoing ability to review the reasonableness of the proposed rate in the future as necessary.

Rates should be set based on known and measureable values such as three years worth of known historical market prices with severe abnormalities removed and any consistent known and measurable historic trend reflected as I have proposed in this testimony. As I have noted, this is the same general approach that has been used in Ameren Missouri's five most recent base rate proceedings to set the NBEC portion of Ameren Missouri's base rate revenue requirement both without an FAC and with an FAC. This approach should be used as the measuring stick to evaluate the reasonableness of Noranda's rate proposal in this proceeding, not predictions of future spot market prices that may or may not be wrong.

Q **CAN YOU PLEASE PROVIDE SOME MORE BACKGROUND ON AMEREN MISSOURI'S HISTORIC USE IN ITS RECENT BASE RATE PROCEEDINGS OF FORWARD MARKET PRICES FOR ENERGY AND ITS OWN PROJECTIONS OF FUTURE MARKET PRICES FOR CAPACITY AN ENERGY?**

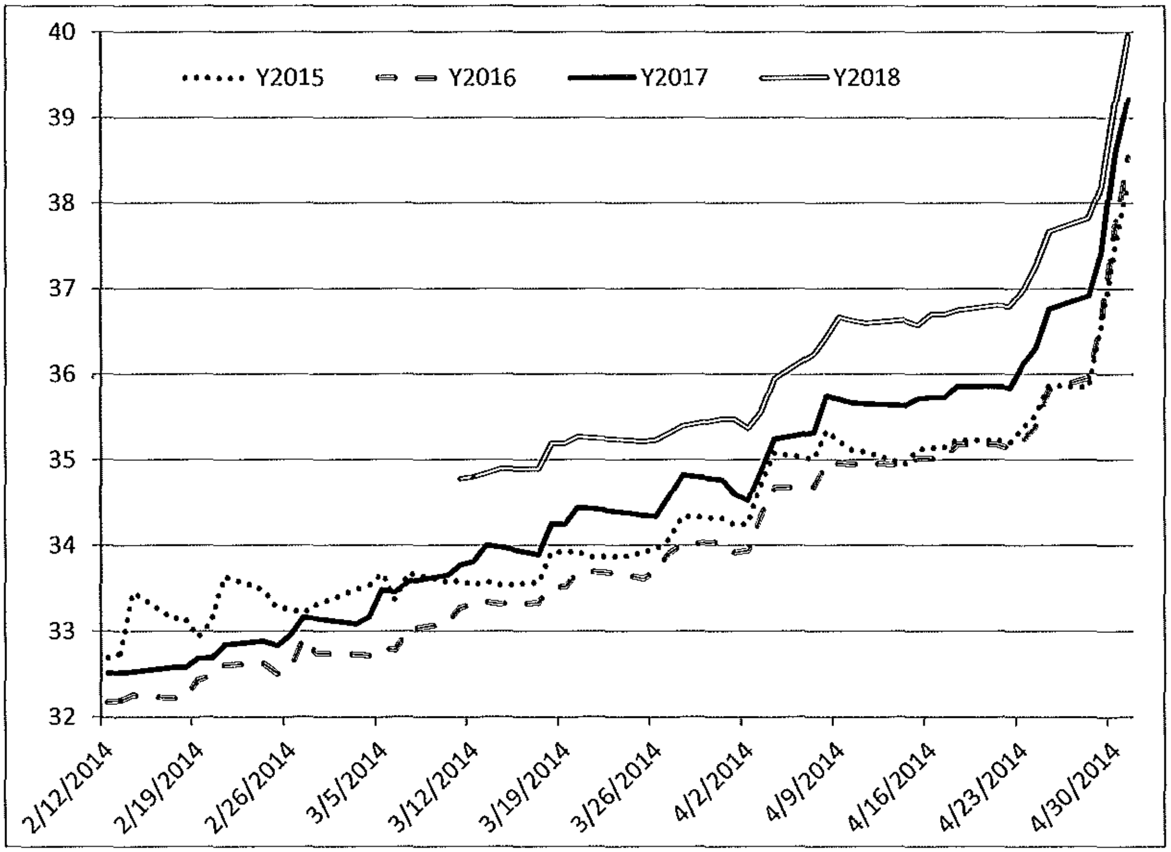
A Yes. As I discussed in detail earlier, for its most recent five base rate proceedings, Ameren Missouri has consistently proposed to use average historical spot energy prices (with any Ameren Missouri-identified anomalies removed) as an input to the determination of the NBEC portion of its base rate revenue requirement. It has not proposed to use forward market prices for energy or other projections of the future market price for energy to determine its NBEC except in the limited context of a temporary placeholder for future delivery months until actual hourly energy prices became available in the proposed true-up period proposed by Ameren Missouri for that rate proceeding. Furthermore, Ameren Missouri witness Schukar in Case No. ER-2007-0002 indicated "[w]e understand that reliance on forward market prices is not appropriate for the purpose of ratemaking in Missouri" (Ameren Missouri witness Schukar Rebuttal in Case No. ER-2007-0002 at 30). This said, Ameren Missouri in those past proceedings has on occasion offered forward market prices for energy on a rolling 12-month basis as anecdotal evidence.

Q PLEASE EXPLAIN HOW FORWARD MARKET PRICES FOR ENERGY ARE CURRENTLY DISTORTED BY THE POLAR VORTEX ANOMALY AND WHAT LESSON WE CAN DRAW FROM THE HURRICANES KATRINA AND RITA MARKET ANOMALY.

A I have already discussed the Polar Vortex Anomaly itself and its impact on actual hourly market prices for energy. In his rebuttal testimony, Mr. Michels provided the following figure, which I repeat here as Figure JRD-5, depicting around-the-clock Indiana Hub forward market prices for 2015, 2016, 2017 and 2018 as traded during and immediately following the Polar Vortex Anomaly as compiled by Ameren Missouri from publications and market quotes.[8]

[8]It is important to note that Indiana Hub and AMMO.UE have a significant basis differential between them due to transmission congestion between them. As a result, any forward energy market product purchased at AMMO.UE would have a lower cost than at Indiana Hub (neglecting any sparsity premiums or discounts due to AMMO.UE being a much less commonly used forward market trading location than Indiana Hub).

Figure JRD-5



As can be seen in Figure JRD-5, there has been a very large increase in forward market prices for energy for 2015, 2016, 2017 and 2018 during this trading period. However, this is not normal and the abnormality can be attributed to the after effects of the Polar Vortex Anomaly. Figure JRD-6 below provides around-the-clock forward market prices for 2015 for Indiana Hub as reported by Platts for the trading days in the period of November 1, 2013 through December 31, 2013 – just before the Polar Vortex Anomaly began.

Figure JRD-6

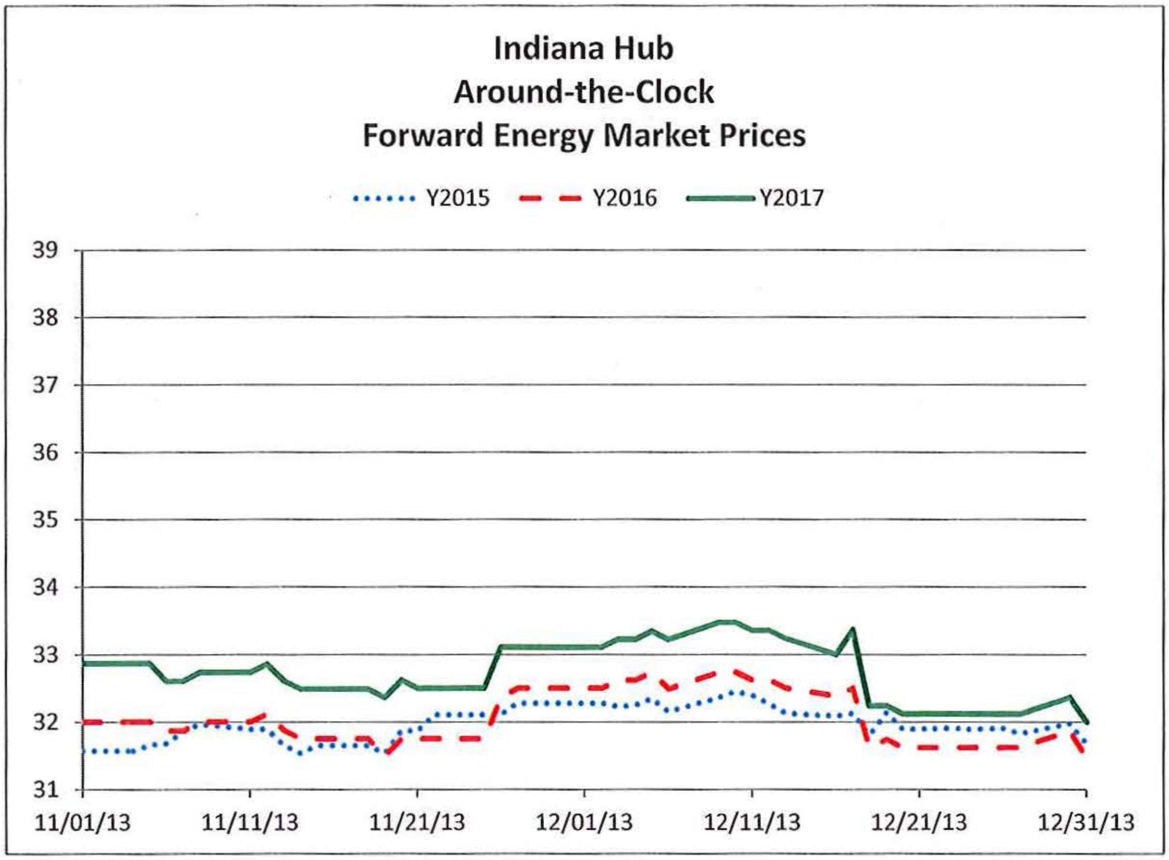
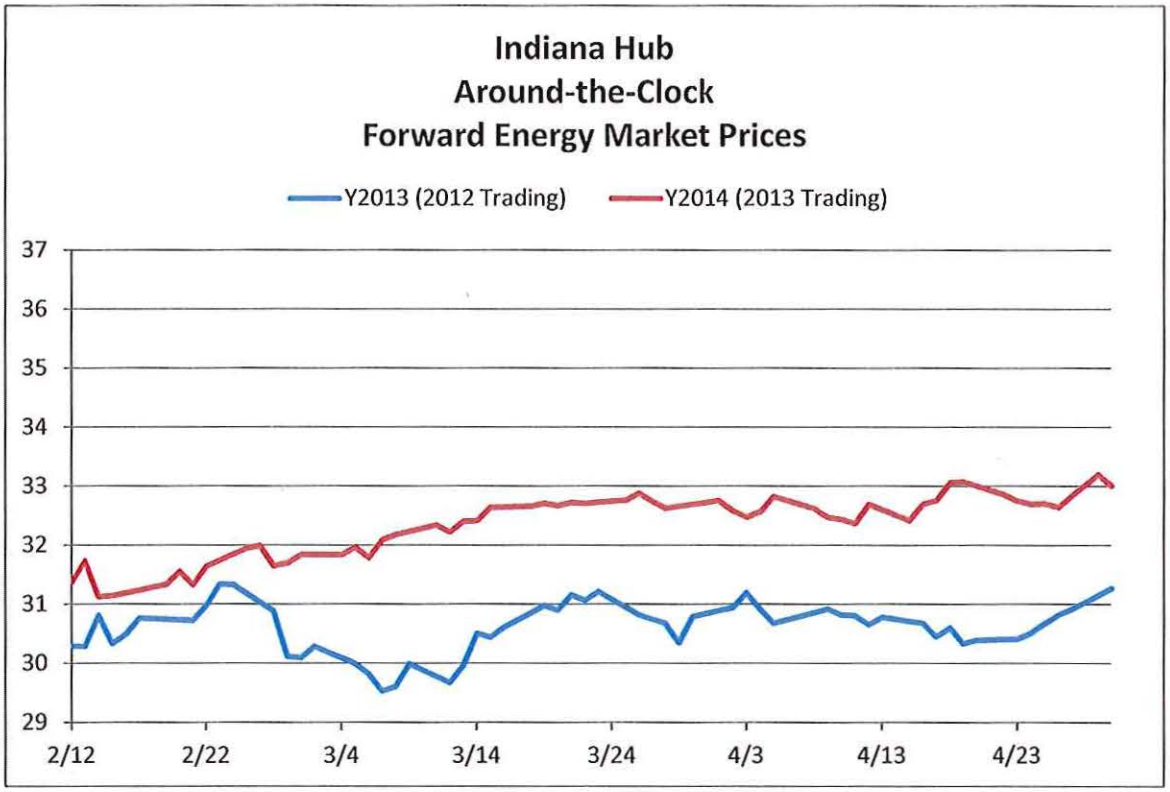


Figure JRD-7 below provides around-the-clock forward market prices for the prompt calendar year (the calendar year immediately following the trading date) for Indiana Hub as reported by Platts for the trading days for the period of February 12 through April 30 of 2012 and 2013 – the same group of trading days in 2012 and 2013 as shown in 2014 during and immediately after the Polar Vortex Anomaly.

Figure JRD-7

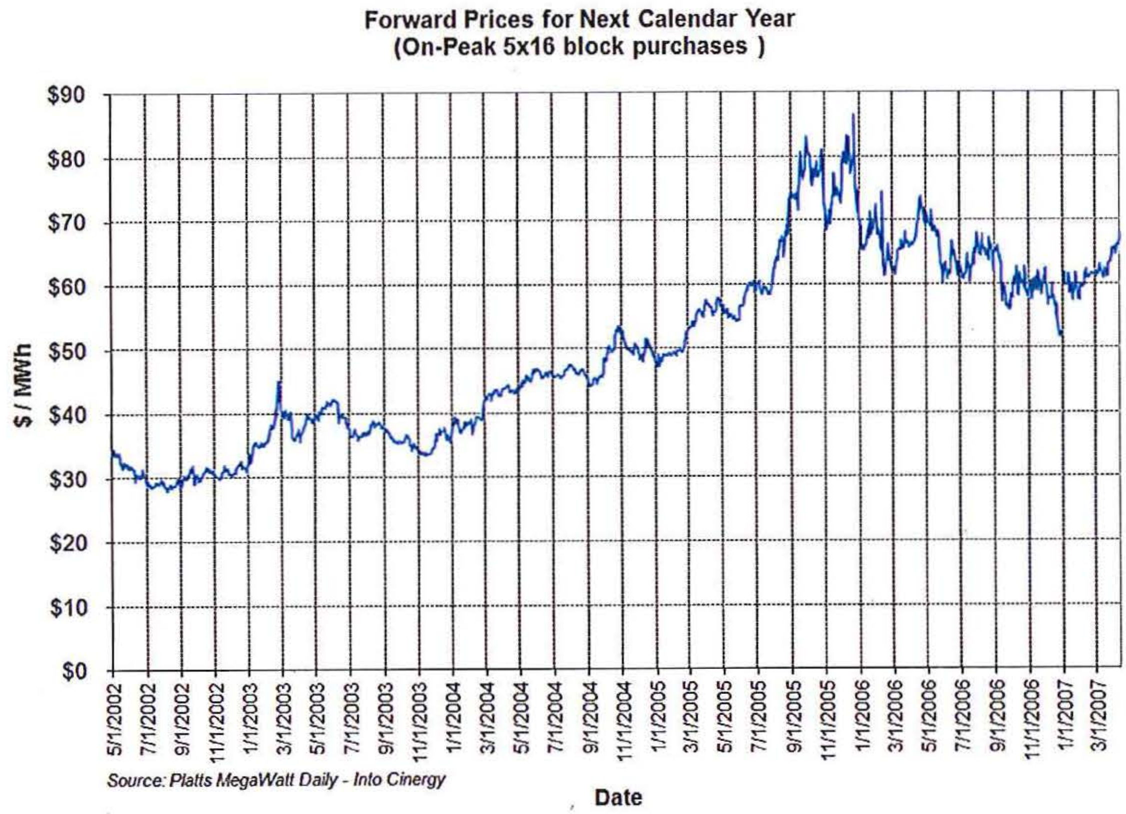


In neither Figure JRD-6 nor Figure JRD-7 do we see the abnormal forward market behavior that we see in Figure JRD-5 during and immediately following the Polar Vortex Anomaly. Current forward market prices are distorted as a result of the aftermath of the Polar Vortex Anomaly and, as a result, cannot be relied upon as a good indicator of future actual hourly energy market prices.

Q **PLEASE COMPARE THIS TO FORWARD ENERGY MARKET PRICES DURING AND FOLLOWING THE HURRICANES KATRINA AND RITA MARKET ANOMALY.**

A Figure JRD-8 below provides on-peak and off-peak forward energy market prices trades at Cinergy Hub, the ancestor of Indiana Hub, from May 2002 through March 2007.

Figure JRD-8



Hurricane Dennis made landfall in the US on July 11, 2005 followed by Katrina on August 29, 2005 and Rita on September 24, 2005. A steep rise in forward energy market prices can be seen to begin in August of 2005 that ultimately peaked in December of 2005. This is generally similar to the rise in forward energy market prices that we have seen in the aftermath of the Polar Vortex Anomaly. Figure JRD-8 also shows that it took until September of 2006 to completely shake off from the forward energy market the aftermath of the Hurricanes Katrina and Rita anomaly. However, the bottom line is that the market did ultimately shake off the anomaly and returned to the then normal consistent year after year upward trend in forward energy market prices that existed until 2008. The same forward energy market recovery should happen again with the Polar Vortex Anomaly.

Q WILL ACTUAL HOURLY ENERGY MARKET PRICES TAKE AS LONG TO RECOVER AS FORWARD ENERGY MARKET PRICES?

A It is unlikely it will take as long largely because the forward energy market reflects fears associated with future risks that are not present in the day-to-day hourly energy market. As shown back on my Figure JRD-4, actual MISO day-ahead hourly energy market prices largely returned to normal levels following the Hurricanes Katrina and Rita anomaly by January of 2006, while, as shown above in Figure JRD-8, rolling 12-month forward energy market prices remained elevated into the summer of 2006. This can also be seen back on my Figure JRD-1 in that annual average hourly energy market prices in that figure for calendar year 2006 are much lower than for calendar year 2005 in that same figure. Similar to what happened after the Hurricanes Katrina and Rita Anomaly, it is reasonable to expect current actual hourly energy market prices will fully return to normal levels much sooner than forward energy market prices.

I. Avoided Generation Resource and Other Avoided Capital Expenditures

Q PLEASE EXPLAIN MR. MICHELS' CRITICISM OF YOUR ANEC IMPACT ESTIMATE NOT CAPTURING SAVINGS FROM AVOIDED GENERATION RESOURCE CAPITAL EXPENDITURES.

Q Mr. Michels asserts that if Noranda's New Madrid facilities ceased operation, Ameren Missouri's addition of any new generation resources could be substantially delayed or even eliminated (Michels Rebuttal at 30). He goes on to suggest it would allow for greater flexibility in addressing environmental regulations, planning for the eventual retirement of aging generators in Ameren Missouri's existing generation fleet and taking steps to transition Ameren Missouri's resource portfolio to one that relies more on cleaner sources of energy (*Id.*).

Q HOW DO YOU RESPOND TO MR. MICHELS WITH RESPECT TO THIS ISSUE?

A Due to Ameren Missouri's current supply portfolio, which is already long on capacity, the issue is a red herring at best. Furthermore, Ameren Missouri has filed previous testimony citing concerns with significant transmission congestion on the Ameren Missouri and AECI transmission systems if Noranda's New Madrid facilities were to be shut down. This transmission congestion could increase costs for both Ameren Missouri and AECI customers. Those increased costs might trigger the need for new transmission capital expenditures. Thus, a shutdown of Noranda's New Madrid facilities might trigger the need for capital expenditures by Ameren Missouri.

In discovery in this current proceeding, Ameren Missouri was asked to identify when it currently projects the need for a major new generation facility if Noranda's New Madrid facilities remain in operation and are served by Ameren Missouri. Ameren Missouri's answer to the data request was that it had not performed the necessary analysis (Ameren Missouri response to Data Request Noranda 4-5). Despite Ameren Missouri's claim it needs to perform an analysis, we know from its February 8, 2013 filing of a Notification of Change in Preferred Resource Plan in Case No. EO-2013-0392, that it will no longer include a new combined cycle gas resource with an in service date of 2029 in its resource plan as a result of changes in its load forecast (Notification of Change in Ameren Missouri's Preferred Resource Plan, Case No. EO-2013-0392, February 8, 2013 at 3). As a result, even if Ameren Missouri continues to serve Noranda's New Madrid facilities, Ameren Missouri will not need to add any major new generation facilities until sometime after 2029 – at least six years after the end of the 10-year term of Noranda's rate proposal in this proceeding. Therefore, it is not a potentially avoidable capital expenditure that should be considered in this proceeding.

Q WHAT IF AMEREN MISSOURI ALSO RETIRED ONE OF ITS EXISTING COAL-FIRED GENERATION FACILITIES EARLY?

A This might accelerate Ameren Missouri's need for a major new generation facility by a few years. However, Ameren Missouri has not announced any such intentions. So, it should not be a determining factor in this proceeding. Furthermore, the continued operation of Ameren Missouri's existing generation facilities will not be a function of Ameren Missouri's load. Those decisions will be primarily driven by the value those generation resources provide to Ameren Missouri's customers in the MISO market versus the cost of environmental compliance and the cost of the additional capital expenditures, if any, necessary to keep those resources operational. How much value that each of Ameren Missouri's existing generation facilities provides to Ameren Missouri customers in the MISO market is not a function of Ameren Missouri's load. Nor are environmental compliance costs or other capital expenditure needs for those generation facilities a function of Ameren Missouri's load.

Q YOU PREVIOUSLY NOTED THAT AMEREN MISSOURI HAS PREVIOUSLY IDENTIFIED INCREASES IN TRANSMISSION CONGESTION COSTS THAT MIGHT BE INCURRED IF NORANDA'S NEW MADRID FACILITIES WERE SHUT DOWN. PLEASE EXPAND UPON THIS ISSUE.

A In Case No. EA-2005-0180, the proceeding in which Noranda became an Ameren Missouri customer, Ameren Missouri witness Edward Pfeiffer filed direct testimony that indicated:

> "If Noranda were to cease operations, the power from these surrounding generating sources would flow to a new sink and destination. This could create significant amounts of congestion in the area until additional outlet capacity could be built. It is unlikely that normal load growth would add new loads to substitute for that of a disappearing Noranda absent a replacement large- load customer. Thus, Noranda' s continued operation is important to avoid congestion on the AmerenUE and AECI transmission systems."

(Ameren Missouri witness Pfeiffer Direct in Case No. EA-2005-0180 at 5).

This indicates that a shutdown of Noranda's New Madrid facilities could lead to increased transmission congestion costs for both Ameren Missouri customers and AECI member system customers. If those increased costs are high enough it could lead to the need to make new transmission capital expenditures in order to address that transmission congestion.

Q HAVE YOU INCLUDED AN ESTIMATE OF THESE COSTS ASSOCIATED WITH CLOSURE OF THE SMELTER?

A No. Were I to do so the benefits of retaining Noranda would be even larger.

III. Conclusion and Revised Estimate

Q PLEASE SUMMARIZE YOUR CONCLUSIONS.

A While certain aspects of the criticism by Mr. Michels and Ms. Kliethermes of my direct testimony ANEC impact estimate are valid, even when (i) my ANEC impact estimate is adjusted to reasonably respond to those specific criticisms and (ii) MISO market settlement and other MISO load-based charges are added in (which should only be done if the small market price reduction from the shutdown of the Noranda New Madrid facilities is also incorporated), I still estimate a combined ANEC and MISO charge impact that is below the $30 per MWh in retail sales revenues that would be provided by Noranda under its rate proposal in this proceeding. Specifically, my revised ANEC impact estimate indicates Ameren Missouri's ANEC (plus its MISO load-based charges not included in ANEC) would decrease between $27.91 and $28.49 for every MWh that would have been sold to Noranda.

With respect to the use of forecasted market prices, they are speculative and generally should not be used in ratemaking. Furthermore, the Polar Vortex Anomaly event of this past winter has distorted the current level of these prices. For these reasons, the ANEC impact should be estimated based on three years of known historical market prices with severe abnormalities removed and any consistent known and measurable trend reflected. This is the approach I have used to develop my revised ANEC impact estimate. Furthermore, while the proposed Noranda rate plan of $30 per MWh provides for up to 2% rate increase for Noranda during each future Ameren Missouri base rate case over the 10-year term of the Noranda proposal, it is my understanding that the Commission is not precluded from reviewing the continued reasonableness of the Noranda rate in future Ameren Missouri rate proceedings.

With respect to the future resource needs of Ameren Missouri, Ameren Missouri is not currently projecting the need for any new generation resources during the 10-year period of Noranda's rate proposal. In fact, its last available projection, which it provided in 2013, is that Ameren Missouri will not need to add a major new generation facility until sometime after 2029. Furthermore, as I discuss in detail in this testimony, the continued operation of Ameren Missouri's existing generation facilities will be a function of market prices and the cost for environmental compliance, not the MW level of Ameren Missouri's load.

Finally, Ameren Missouri has in previous proceedings before the Commission raised concerns with increased transmission congestion costs if Noranda's New Madrid facilities were to be shut down. This increase in transmission congestion could increase costs for Ameren Missouri customers and Associated Electric Cooperatives, Inc. ("AECI") member system customers. It could also require these two utility systems to incur new capital expenditures on their respective transmission systems to address the increased transmission congestion. As a result, a shutdown of Noranda's New Madrid facilities could actually require Ameren Missouri to incur capital expenditures that it would not have otherwise had to incur.

My Schedule JRD-Surrebuttal-1 provides a high level summary of my revised ANEC impact estimate and Schedules JRD-Surrebuttal-2 and JRD-Surrebuttal-3 provide the underlying detail for that schedule. My revisions can be summarized as follows:

- I have updated the original core components of Ameren Missouri's ANEC that were included in my direct testimony estimate of $27.05 per MWh to reflect:
  - The AMMO.UE MISO pricing node rather than the AECI.AMMO pricing node;
  - The AECI 3.5% loss factor;

- The use of normalized historical energy market prices for the most recent 36 month period with the Polar Vortex Anomaly removed;

- The effect of the estimated 1.5% reduction in energy market prices due to a shutdown of Noranda's load on the avoided cost of clearing the Noranda load in the MISO energy market; and

- The 2014-2015 MISO Planning Resource Auction capacity price of $16.75 per MW-day.

- I have expanded my ANEC impact estimate to include all of Ameren Missouri's material MISO market settlement charges and credits that are materially sensitive to the amount of load served by Ameren Missouri.

- I have expanded my ANEC impact estimate to include the impact of the estimated 1.5% reduction in energy market prices due to a shutdown of Noranda's load on Ameren Missouri's off-system energy sales revenues and purchased power costs.

- I have expanded my ANEC impact estimate to include the very small drop in Ameren Missouri's Schedule 26 regional transmission charges that would result from a shutdown of Noranda's load.

- I have added to my ANEC impact estimate the MISO administration charges that Ameren Missouri would avoid due to a shutdown of the Noranda load.

As I have noted, the net impact of all of the above adjustments is to raise my direct testimony estimate of Ameren Missouri's incremental cost savings from a shutdown of the Noranda load from $27.05 for every MWh that would have been sold to Noranda to a range of $27.91 to $28.49 for every MWh that would have been sold to Noranda. However, this revised ANEC and MISO administration cost savings estimate is still $1.51 per MWh to $2.09 per MWh lower than the $30 per MWh rate proposed by Noranda.

Q **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A Yes.

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Ameren Missouri
Missouri Public Service Commission Case No. EC-2014-0224

Updated and Expanded Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and MISO Administration Charges Under a Noranda Shutdown

	Using Average of Historic Energy Market Prices for May 2011 through April 2014 with January through March of 2014 Replaced with the Average of January through March of 2012 and 2013		Using Average of Historic Energy Market Prices for January 2011 through December 2013	
Description	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Updated Core ANEC Components	$ 118,406,340	$ 28.40	$ 120,828,949	$ 28.98
Expanded ANEC MISO Market Settlement Components	$ (762,557)	$ (0.18)	$ (762,557)	$ (0.18)
Expanded ANEC Off-System Energy Sales Revenue and Purchased Power Cost	$ (2,626,080)	$ (0.63)	$ (2,626,080)	$ (0.63)
Expanded ANEC MISO Transmission Components	$ 54,950	$ 0.01	$ 54,950	$ 0.01
Subtotal of All Affected ANEC Components	$ 115,072,653	$ 27.60	$ 117,495,262	$ 28.18
MISO Transmission Administration Charges	$ 876,764	$ 0.21	$ 876,764	$ 0.21
MISO Market Administration Charges	$ 395,425	$ 0.09	$ 395,425	$ 0.09
Subtotal of All Affected MISO Administration Charges	$ 1,272,189	$ 0.31	$ 1,272,189	$ 0.31
Total of All Affected ANEC Components and MISO Administration Charges	$ 116,344,842	$ 27.91	$ 118,767,451	$ 28.49

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Ameren Missouri
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Updated and Expanded Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and MISO Administration Charges Under a Noranda Shutdown

(Using Average of Historic Energy Market Prices for May 2011 through April 2014 with January through March of 2014 Replaced with the Average of January through March of 2012 and 2013)

Description	Applicable Billing Units for Retail Sales to Noranda (grossed up for AECI Losses of 3.5%)	Historical Market Price	Forecasted Rate	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Net Energy, Transmission Loss and Congestion Costs	4,314,915 MWh	$ 26.69 per MWh		$ 115,165,081	$ 27.62
1.5% Market Price Reduction Impact on Net Energy, Transmission Loss and Congestion Costs	4,314,915 MWh	$ (0.40) per MWh		$ (1,727,476)	$ (0.41)
Net Capacity Costs	201,180 MW-days	$ 16.75 per MW-day		$ 3,369,771	$ 0.81
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,314,915 MWh		$ 0.37 per MWh	$ 1,598,964	$ 0.38
Updated Core ANEC Components				**$ 118,406,340**	**$ 28.40**
MISO Day-Ahead RSG Distribution Amount	4,314,915 MWh	per MWh			
MISO Real-Time Distribution of Losses Amount	4,314,915 MWh	per MWh			
MISO Real-Time Miscellaneous Amount	4,314,915 MWh	per MWh			
MISO Real-Time Net Inadvertent Amount	4,314,915 MWh	per MWh			
MISO Real-Time Revenue Neutrality Uplift Amount	4,314,915 MWh	per MWh			
MISO Real-Time RSG First Pass Distribution Amount	4,314,915 MWh	per MWh			
MISO Regulation Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Spinning Reserve Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Supplemental Reserve Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Auction Revenue Rights (ARR) Stage 2 Distribution Amount (see Schedule JRD-Surrebuttal-5)	502.62 MW-years	per MW-year			
Expanded ANEC MISO Market Settlement Components				**$ (762,557)**	**$ (0.18)**
1.5% Market Price Reduction Impact on other OSS Revenues and PP Costs (see Schedule JRD-Surrebuttal-8)	N/A			$ (2,626,080)	$ (0.63)
Expanded ANEC Off-System Energy Sales Revenue and Purchased Power Cost Components				**$ (2,626,080)**	**$ (0.63)**
MISO Tariff Schedule 26 Network Upgrade Charge (see Schedule JRD-Surrebuttal-4)	N/A			$ 54,950	$ 0.01
Expanded ANEC MISO Transmission Components				**$ 54,950**	**$ 0.01**
Sutotal of All Affected ANEC Components				**$ 115,072,653**	**$ 27.60**

Description	Applicable Billing Units for Retail Sales to Noranda (grossed up for AECI Losses of 3.5%)	Historical Market Price	Forecasted Rate	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
MISO Tariff Schedule 10 Administration Charge (Energy Rate Portion)	4,314,915 MWh		$ 0.09 per MWh	$ 381,971	$ 0.09
MISO Tariff Schedule 10 Administration Charge (Demand Rate Portion)	4,499,840 MWh		$ 0.07 per MWh	$ 293,300	$ 0.07
MISO Tariff Schedule 10-FERC Charge (MISO FERC Assessment)	4,499,840 MWh		$ 0.04 per MWh	$ 201,493	$ 0.05
MISO Transmission Administration Charges				**$ 876,764**	**$ 0.21**
MISO Day-Ahead Market Administration (MISO Schedule 17)	4,314,915 MWh		$ 0.07 per MWh	$ 323,058	$ 0.08
MISO Day-Ahead Schedule 24 Allocation Amount	4,314,915 MWh		per MWh		
MISO Real-Time Market Administration Amount (MISO Schedule 17)	MWh		$ 0.07 per MWh		
MISO Real-Time Schedule 24 Allocation Amount	MWh		per MWh		
MISO Market Administration Charges				**$ 395,425**	**$ 0.09**
Subtotal of All Affected MISO Administration Charges				**$ 1,272,189**	**$ 0.31**
Total of All Affected ANEC Components and MISO Administration Charges				**$ 116,344,842**	**$ 27.91**

Sources:

The $26.69 per MWh Historical Market Price used for the Net Energy, Transmission Loss and Congestion Cost savings estimate is the around-the-clock average of the day-ahead hourly LMPs for the AMMO.UE Node for the 36 months ending April 30, 2014 (with January through March of 2014 replaced with the average of January through March of 2012 and 2013) as posted on the MISO website. This downward adjusted 36 month normalization period was selected to exclude the Polar Vortex anomaly event of January through March of 2014.

The Market Price of $16.75 per MW-day used for the Net Capacity Cost savings estimate is the market clearing price for Zonal Resource Credits (ZRCs) for Local Resource Zone 5 (Missouri) in the MISO's Planning Resource Auction for the MISO 2014/2015 Planning Year as reported by MISO on its website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=174894.

The Forecasted MISO Tariff Schedule 26-A rate of $0.37 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2014 as of August 6, 2013 as posted on the MISO website at www.misoenergy.org.

The MISO Market Settlement Components calculated from historical Ameren Missouri MISO Market Settlement amounts from 2011 through 2013 that are sensitive to load. 2013 data was ultimately utilized to be conservative since Ameren Missouri's Stage 2 ARR MW entitlements were only known for 2013 and the average non-ARR Stage 2 Market Settlement Amounts for 2011 through 2013 were lower than in 2013 alone.

All MISO administration charges, except for MISO Schedule 24, were based on the latest rate posted on the MISO website. Schedule 24 charges were based on Ameren Missouri's actual 2013 MISO Schedule 24 costs.

Notes:

Noranda Retail Sales assumed to be 4,169,000 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor at Noranda's meter. These sales gross up to 4,314,915 MWh at the AECI/MISO border due to AECI's 3.5% loss factor under Noranda transmission service agreement with AECI.

201,180 MW-days = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 107.3% (UCAP Planning Reserve Margin) x 102.2% (MISO Transmission Losses) x 365 days

513.68 MW-years = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 102.2% (MISO Transmission Losses)

4,499,840 MWh = 513.68 MW-years x 8,760 hours per year

502.62 MW-years = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor)

Ameren Missouri
Missouri Public Service Commission Case No. EC-2014-0224

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Updated and Expanded Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and MISO Administration Charges Under a Noranda Shutdown

(Using Average of Historic Energy Market Prices for January 2011 through December 2013)

Description	Applicable Billing Units for Retail Sales to Noranda (grossed up for AECI Losses of 3.5%)	Historical Market Price	Forecasted Rate	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Net Energy, Transmission Loss and Congestion Costs	4,314,915 MWh	$ 27.26 per MWh		$ 117,624,583	$ 28.21
1.5% Market Price Reduction Impact on Net Energy, Transmission Loss and Congestion Costs	4,314,915 MWh	$ (0.41) per MWh		$ (1,764,369)	$ (0.42)
Net Capacity Costs	201,180 MW-days	$ 16.75 per MW-day		$ 3,369,771	$ 0.81
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,314,915 MWh		$ 0.37 per MWh	$ 1,598,964	$ 0.38
Updated Core ANEC Components				**$ 120,828,949**	**$ 28.98**
MISO Day-Ahead RSG Distribution Amount	4,314,915 MWh	per MWh			
MISO Real-Time Distribution of Losses Amount	4,314,915 MWh	per MWh			
MISO Real-Time Miscellaneous Amount	4,314,915 MWh	per MWh			
MISO Real-Time Net Inadvertent Amount	4,314,915 MWh	per MWh			
MISO Real-Time Revenue Neutrality Uplift Amount	4,314,915 MWh	per MWh			
MISO Real-Time RSG First Pass Distribution Amount	4,314,915 MWh	per MWh			
MISO Regulation Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Spinning Reserve Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Supplemental Reserve Cost Distribution Amount	4,314,915 MWh	per MWh			
MISO Auction Revenue Rights (ARR) Stage 2 Distribution Amount (see Schedule JRD-Surrebuttal-5)	502.62 MW-years	per MW-year			
Expanded ANEC MISO Market Settlement Components				**$ (762,557)**	**$ (0.18)**
1.5% Market Price Reduction Impact on other OSS Revenues and PP Costs (see Schedule JRD-Surrebuttal-8)	N/A			$ (2,626,080)	$ (0.63)
Expanded ANEC Off-System Energy Sales Revenue and Purchased Power Cost Components				**$ (2,626,080)**	**$ (0.63)**
MISO Tariff Schedule 26 Network Upgrade Charge (see Schedule JRD-Surrebuttal-4)	N/A			$ 54,950	$ 0.01
Expanded ANEC MISO Transmission Components				**$ 54,950**	**$ 0.01**
Subtotal of All Affected ANEC Components				**$ 117,495,262**	**$ 28.18**

Description	Applicable Billing Units for Retail Sales to Noranda (grossed up for AECI Losses of 3.5%)	Historical Market Price	Forecasted Rate	Estimated Annual Reduction in Ameren Missouri ANEC and MISO Administration Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
MISO Tariff Schedule 10 Administration Charge (Energy Rate Portion)	4,314,915 MWh		$ 0.09 per MWh	$ 381,971	$ 0.09
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MISO Tariff Schedule 10-FERC Charge (MISO FERC Assessment)	4,499,840 MWh		$ 0.04 per MWh	$ 201,493	$ 0.05
MISO Transmission Administration Charges				**$ 876,764**	**$ 0.21**
MISO Day-Ahead Market Administration (MISO Schedule 17)	4,314,915 MWh		$ 0.07 per MWh	$ 323,058	$ 0.08
MISO Day-Ahead Schedule 24 Allocation Amount	4,314,915 MWh		per MWh		
MISO Real-Time Market Administration Amount (MISO Schedule 17)	MWh		$ 0.07 per MWh		
MISO Real-Time Schedule 24 Allocation Amount	MWh		per MWh		
MISO Market Administration Charges				**$ 395,425**	**$ 0.09**
Subtotal of All Affected MISO Administration Charges				**$ 1,272,189**	**$ 0.31**
Total of All Affected ANEC Components and MISO Administration Charges				**$ 118,767,451**	**$ 28.49**

Sources:

The $27.26 per MWh Historical Market Price used for the Net Energy, Transmission Loss and Congestion Cost savings estimate is the around-the-clock average of the day-ahead hourly LMPs for the AMMO.UE Node for the 36 months ending December 31, 2013 as posted on the MISO website. This 36 month normalization period was selected to exclude the Polar Vortex anomaly event of January through March of 2014.

The Market Price of $16.75 per MW-day used for the Net Capacity Cost savings estimate is the market clearing price for Zonal Resource Credits (ZRCs) for Local Resource Zone 5 (Missouri) in the MISO's Planning Resource Auction for the MISO 2014/2015 Planning Year as reported by MISO on its website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=174894.

The Forecasted MISO Tariff Schedule 26-A rate of $0.37 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2014 as of August 6, 2013 as posted on the MISO website at www.misoenergy.org.

The MISO Market Settlement Components calculated from historical Ameren Missouri MISO Market Settlement amounts from 2011 through 2013 that are sensitive to load. 2013 data was ultimately utilized to be conservative since Ameren Missouri's Stage 2 ARR MW entitlements were only known for 2013 and the average non-ARR Stage 2 Market Settlement Amounts for 2011 through 2013 were lower than in 2013 alone.

All MISO administration charges, except for MISO Schedule 24, were based on the latest rate posted on the MISO website. Schedule 24 charges were based on Ameren Missouri's actual 2013 MISO Schedule 24 costs.

Notes:

Noranda Retail Sales assumed to be 4,169,000 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor at Noranda's meter. These sales gross up to 4,314,915 MWh at the AECI/MISO border due to AECI's 3.5% loss factor under Noranda transmission service agreement with AECI.

201,180 MW-days = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 107.3% (UCAP Planning Reserve Margin) x 102.2% (MISO Transmission Losses) x 365 days

513.68 MW-years = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 102.2% (MISO Transmission Losses)

4,499,840 MWh = 513.68 MW-years x 8,760 hours per year

502.62 MW-years = 4,314,915 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor)

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Load-Sensitive MISO Market Settlement Charges and Credits and MISO Schedule 24 Charges

MISO Market Settlment Charge Type	2011 Charges	2011 Load	2012 Charges	2012 Load	2013 Charges	2013 Load	2011 per MWh	2012 per MWh	2013 per MWH	2011-2013 Normalized Market Cost per MWh
DA Revenue Sufficiency Guarantee Distribution Amount										
RT Distribution of Losses Amount										
RT Miscellaneous Amount										
RT Net Inadvertent Distribution Amount										
RT Revenue Neutrality Uplift Amount										
RT Revenue Sufficiency Guarantee First Pass Dist Amount										
RT Regulation Cost Distribution Amount										
RT Spinning Reserve Cost Distribution Amount										
RT Supplemental Reserve Cost Distribution Amount										
Total Load-Sensitive Non-ARR MISO Market Settlement Charges										

Source: Ameren Missouri Response to Data Request MPSC 0010

MISO Administration										Latest Known and Measurable Rate (2013) (per MWh)
DA Schedule 24 Allocation Amount										
RT Schedule 24 Allocation Amount										
Estimated RT to DA Billing Unit Ratio for Schedule 24 and Market Administration Charges										

Source: Ameren Missouri Response to Data Request MPSC 0010

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Missouri Public Service Commission Case No. EC-2014-0224

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Load-Sensitivity of MISO Auction Revenue Right ("ARR") Stage 2 Distribution Amounts

Peak

	Stage 1 Nomination Cap (MW)	Stage 1A Allocation (MW)	Restoration Allocation (MW)	Unterminated LTTR (MW)	Stage 1B Allocation (MW)	Stage 2 Entitlement (MW)
Winter 2012 (December 2012 - February 2013)						
Spring 2013						
Summer 2013						
Fall 2013						
Winter 2013 (December 2013 - February 2014)						
Average CY 2013						

Source: Ameren Missouri Response to Data Request Noranda 4-27 i.

Off-Peak

	Nomination Cap (MW)	Stage 1A Allocation (MW)	Restoration Allocation (MW)	Unterminated LTTR (MW)	Stage 1B Allocation (MW)	Stage 2 Entitlement (MW)
Winter 2012 (December 2012 - February 2013)						
Spring 2013						
Summer 2013						
Fall 2013						
Winter 2012 (December 2013 - February 2014)						
Average CY 2013						

Source: Ameren Missouri Response to Data Request Noranda 4-27 i.

Total 2013 ARR Stage 2 Distribution Amount Settlement		(Ameren Missouri Response to Data Request MPSC 0010)
Average 2013 ARR Stage 2 Entitlement (MW)		(80/168ths Peak and 88/168ths Off-Peak)
Estimated 2013 ARR Stage 2 Distribution Amount per MW-year of load		

Ameren Missouri
Missouri Public Service Commission Case No. EC-2014-0224

Ameren Missouri MISO Schedule 26 Charges
Under a Noranda Shutdown

Line	Description		Amount		Source
1	Current MISO Schedule 26 Annual Revenue Requirement for MISO Transmission Pricing Zone 3B	$	11,758,840.98		MISO Workbook "Schedule 26 Apr 2014.xlsx" at "Summary", Row 19
2	Current MISO Schedule 26 Rate Divisor for MISO Transmission Pricing Zone 3B		6,847,897	kW	MISO Workbook "Schedule 26 Apr 2014.xlsx" at "Summary", Row 19
3	**Current MISO Schedule 26 Rate for Transmission Pricing Zone 3B**	**$**	**0.1431**	**per kW-month**	Line 1 / Line 2 / 12 months
4	Noranda Annual Retail Sales		4,169,000,000	kWh	Assumed to be 4,169,000 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor.
5	AECI Loss Factor		3.50%		Noranda-AECI Transmission Service Agreement
6	MISO Transmission Loss Factor		2.15%		MISO file "Trans_Loss_Percentage_2012-13_June_Post.xls"
7	Noranda Monthly MISO Coincident Peak Demand with Losses		513,429	kW	Line 4 x (1 + Line 5) x (1 + Line 6) / 8,760 hours / 98% Load Factor x 100% Coincidence Factor
8	Noranda Shutdown MISO Schedule 26 Rate Divisor for MISO Transmission Pricing Zone 3B		6,334,468	kW	Line 2 - Line 7
9	**Noranda Shutdown MISO Schedule 26 Rate for MISO Transmission Pricing Zone 3B**	**$**	**0.1547**	**per kW-month**	Line 1 / Line 8 / 12 months
10	January 2013 Ameren Missouri MISO Network Transmission Service		6,202,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
11	February 2013 Ameren Missouri MISO Network Transmission Service		6,381,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
12	March 2013 Ameren Missouri MISO Network Transmission Service		5,723,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
13	April 2013 Ameren Missouri MISO Network Transmission Service		5,096,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
14	May 2013 Ameren Missouri MISO Network Transmission Service		5,960,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
15	June 2013 Ameren Missouri MISO Network Transmission Service		7,238,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
16	July 2013 Ameren Missouri MISO Network Transmission Service		7,503,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
17	August 2013 Ameren Missouri MISO Network Transmission Service		7,713,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
18	September 2013 Ameren Missouri MISO Network Transmission Service		7,542,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
19	October 2013 Ameren Missouri MISO Network Transmission Service		6,017,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
20	November 2013 Ameren Missouri MISO Network Transmission Service		5,707,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
21	December 2013 Ameren Missouri MISO Network Transmission Service		6,355,000	kW	Ameren Missouri (Union Electric Company) 2013 FERC Form 1 Page 400, Column (e)
22	Current Ameren Missouri 12-CP Transmission Load (including losses)		6,453,083	kW	Average of Lines 10 through 21
23	**Current Annual Ameren Missouri MISO Schedule 26 Billing Units**		**77,437,000**	**kW-months**	Sum of Lines 10 through 21
24	**Noranda Shutdown Annual Ameren Missouri Schedule 26 Billing Units**		**71,275,851**	**kW-months**	(Line 23 - Line 7) x 12 months
25	**Current Ameren Missouri MISO Schedule 26 Charges (using Schedule 26 Rate as of April 2014)**	**$**	**11,080,888**		Line 23 x Line 3
26	**Noranda Shutdown Ameren Missouri MISO Schedule 26 Charges (using Schedule 26 Rate as of April 2014)**	**$**	**11,025,938**		Line 24 x Line 9
27	**Estimated Annual Ameren Missouri MISO Schedule 26 Charge Savings from Noranda Shutdown**	**$**	**54,950**		Line 25 - Line 26

Statistical Analysis of Historical Hourly Market Energy Price Changes as a Function of Hourly Load Changes

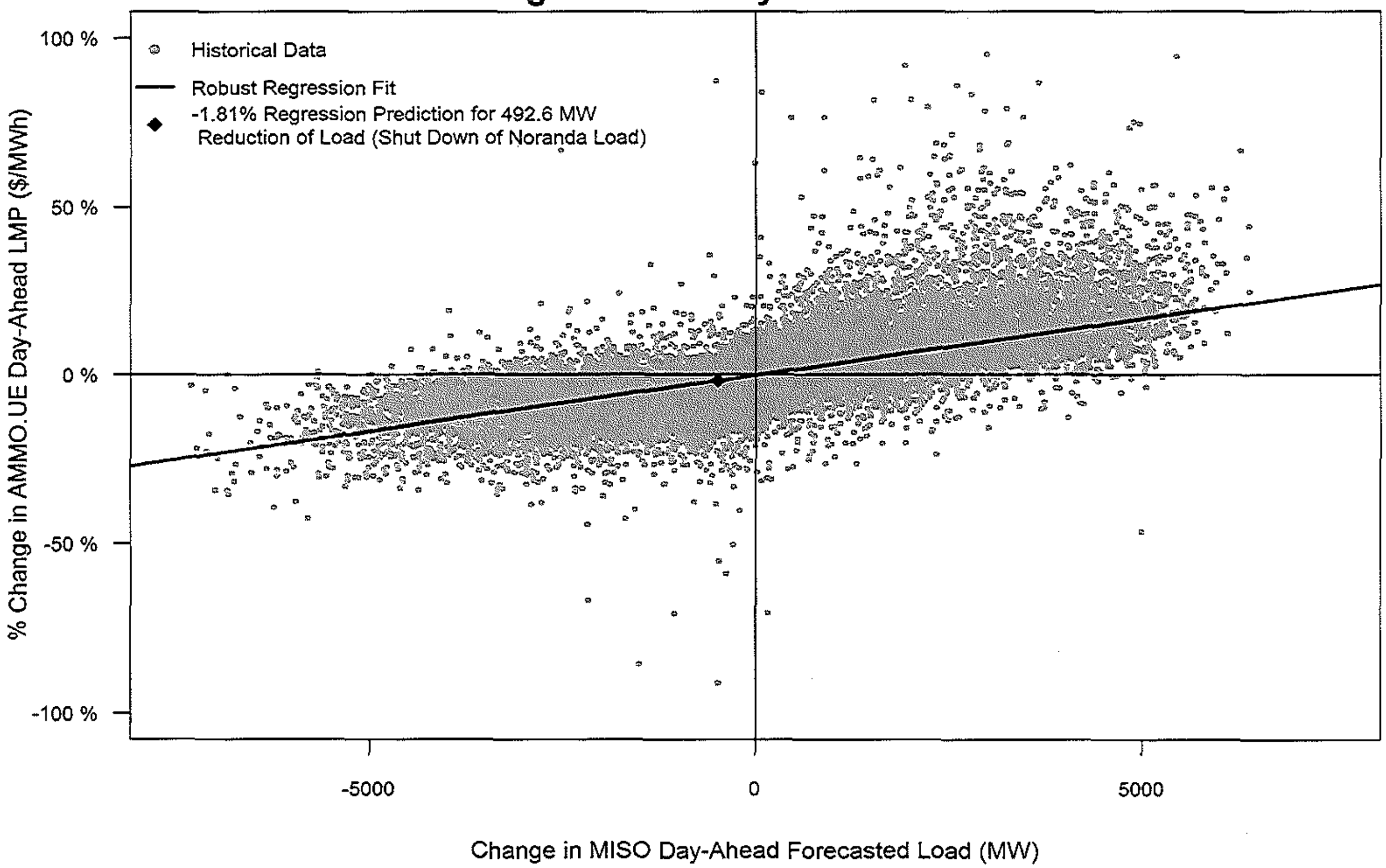
Line No	Percentile	(a) Historical Per Unit % Change in Hourly AMMO.UE Day-Ahead LMP	(b) = (a) * (-492.6 MW) Estimated Historical % Change in Hourly AMMO.UE Day-Ahead LMP Resulting from 492.6 MW Reduction in Load
	(%)	(%)	(%)
1	5%	-0.0089%	4.39%
2	10%	-0.0022%	1.10%
3	15%	-0.0002%	0.09%
4	20%	0.0007%	-0.33%
5	25%	0.0013%	-0.64%
6	30%	0.0018%	-0.86%
7	35%	0.0022%	-1.08%
8	40%	0.0027%	-1.31%
9	45%	0.0031%	-1.52%
10	50% (Median)	0.0036%	-1.76%
11	55%	0.0041%	-2.02%
12	60%	0.0047%	-2.32%
13	65%	0.0054%	-2.65%
14	70%	0.0062%	-3.06%
15	75%	0.0073%	-3.58%
16	80%	0.0087%	-4.28%
17	85%	0.0108%	-5.34%
18	90%	0.0145%	-7.12%
19	95%	0.0237%	-11.66%
20	Mean	0.0046%	-2.26%

Notes:

Data Source: AMMO.UE Day-Ahead LMPs and MISO MTLF Day-Ahead Hourly Load Forecast from 2011-2013 Downloaded from MISO Website

492.6 MW = Average Hourly Noranda Load Including Transmission Loses (i.e. (4,169,000 MWh)*1.035)/8,760 Hours)

Robust Linear Regression Result
Percent Change in AMMO.UE Day-Ahead LMP as a Function of the Change in MISO Day-Ahead Forecasted Load



Notes

Data Source: AMMO.UE Day-Ahead LMPs and MISO MTLF Day-Ahead Hourly Load Forecast from 2011-2013 Downloaded from MISO Website

492.6 MW = Average Hourly Noranda Load Including Transmission Loses (i.e. (4,169,000 MWh)*1.035)/8,760 Hours)

Estimate of Annual Reduction in Ameren Missouri Off-System Energy Sales Revenues and Purchased Power Expenses Due to the Market Energy Price Reduction from a Noranda Load Shutdown

Line No	Description	(a) Off-System Energy Sales Revenues ($)	(b) Purchase Power Expense ($)	(c) = (a) + (b) OSS Revenues Net of Purchased Power Expenses ($)	Source
1	2011 Subtotal	[redacted]	[redacted]	[redacted]	Ameren Missouri Monthly FAC Reports Jan 2011 thru Dec 2011, Page - 5C p1
2	2012 Subtotal				Ameren Missouri Monthly FAC Reports Jan 2012 thru Dec 2012, Page - 5C p1
3	2013 Subtotal				Ameren Missouri Monthly FAC Reports Jan 2013 thru Dec 2013, Page - 5C p1
4	2011 - 2013 Average	[redacted]	[redacted]	(175,072,029)	(Line 1 + Line 2 + Line 3) / 3
5	Estimated % Reduction in Market Energy Prices from a Noranda Load Shutdown			1.50%	Schedule JRD-7, conservatively rounded down to 1.5%
6	Estimated Reduction in Off-System Energy Sales Revenues and Purchased Power Expenses			(2,626,080)	Line 4 * Line 5

National Weather Service Weather Forecast Office

Chicago, IL

Coldest December-March Period in Chicago History

CHICAGO:

THE IMPRESSIVE COLD THIS PAST WINTER CONTINUED DURING MARCH...WITH A MONTHLY AVERAGE TEMPERATURE OF ONLY 31.7 DEGREES FOR THE MONTH. THIS RANKS AS THE 19TH COLDEST MARCH ON RECORD IN CHICAGO. HOWEVER...OF EVEN MORE INTEREST IS THE FACT THAT WITH THE ABNORMALLY COLD MARCH ACROSS THE AREA...THIS MADE THE AVERAGE TEMPERATURE FOR THE DECEMBER THROUGH MARCH PERIOD IN CHICAGO 22.0 DEGREES...WHICH IS THE COLDEST SUCH PERIOD ON RECORD FOR CHICAGO DATING BACK TO 1872!

HERE IS A LIST OF THIS YEARS DECEMBER THROUGH MARCH AVERAGE TEMPERATURE RELATED TO THE OTHER COLDEST SUCH PERIODS ON RECORD IN CHICAGO:

RANK	AVERAGE DEC-MAR TEMP	YEAR
1.	22.0	2013-14
2.	22.3	1903-04
3.	22.5	1977-78
	22.5	1892-93
5.	22.7	1978-79

ROCKFORD:

UNSEASONABLY COLD CONDITIONS ALSO OCCURRED IN ROCKFORD IN MARCH. THE AVERAGE MONTHLY TEMPERATURE WAS 29.6 DEGREES...WHICH WAS THE 12TH COLDEST MARCH ON RECORD. THE DECEMBER THROUGH MARCH AVERAGE TEMPERATURE FOR ROCKFORD WAS 18.4 DEGREES. THIS RANKS AS THE 2ND COLDEST SUCH PERIOD ON RECORD IN ROCKFORD DATING BACK TO 1906!

HERE IS A LIST OF THIS YEARS DECEMBER THROUGH MARCH AVERAGE TEMPERATURE RELATED TO THE OTHER COLDEST SUCH PERIODS ON RECORD IN ROCKFORD:

RANK	AVERAGE DEC-MAR TEMP	YEAR
1.	18.2	1977-78
2.	18.4	2013-14
3.	18.5	1978-79
4.	19.1	1911-12
5.	21.0	1981-82

March Monthly Climate Reports: Chicago | Rockford

March Climate Summary

Return to Latest News

Web Site Owner:
National Weather Service
Chicago, IL Weather Forecast Office
333 West University Drive
Romeoville, IL 60446
815-834-1435 8am-8pm
Page Author: LOT Webmaster
Web Master's E-mail: w-lot.webmaster@noaa.gov
Page last modified: 10-Jun-2008 4:22 PM UTC

Schedule JRD-Surrebuttal-9

Winter 2013-2014 Operations and Market Performance

MISO

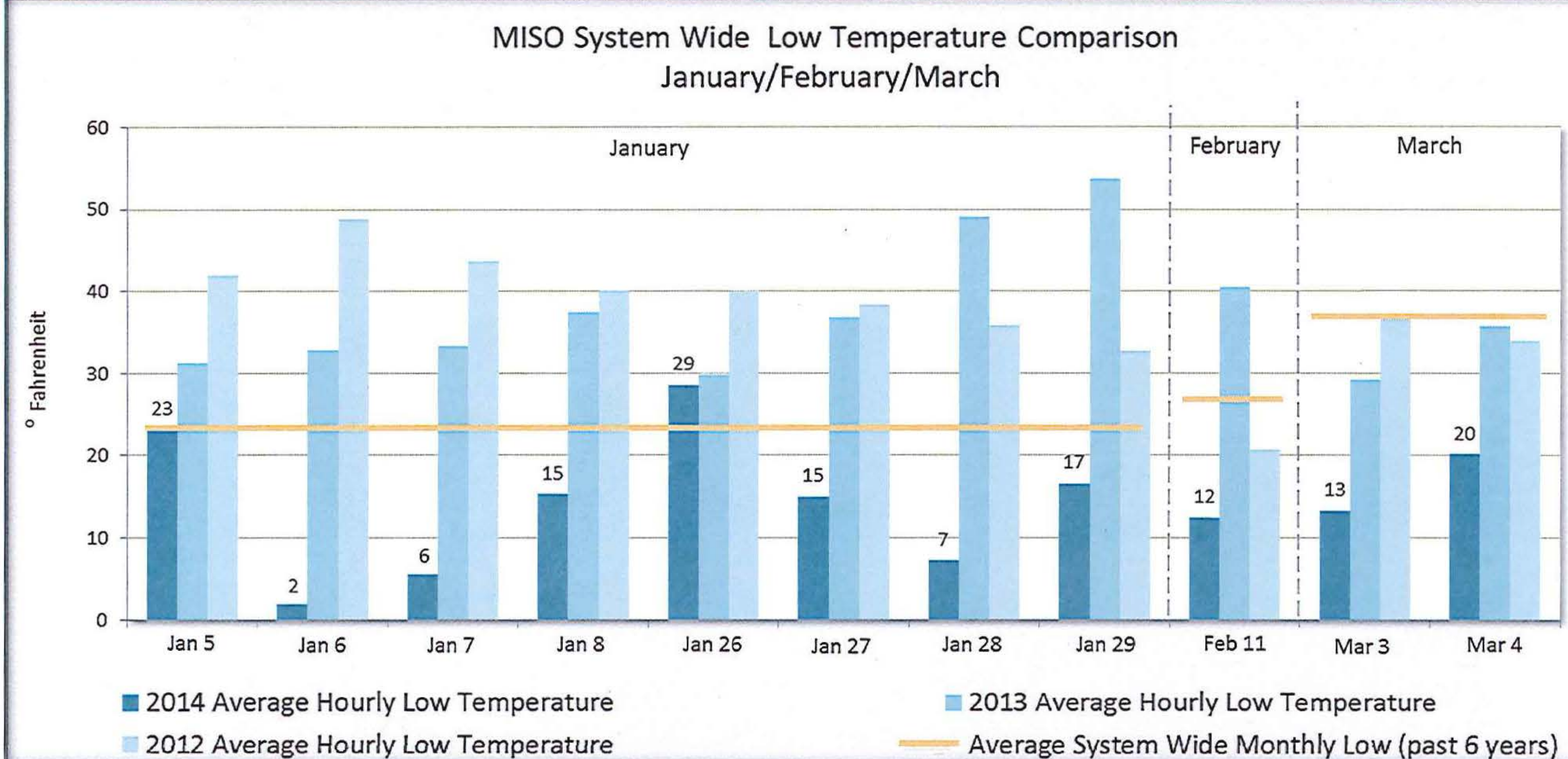
Richard Doying
Midcontinent Independent System Operator

April 1, 2014

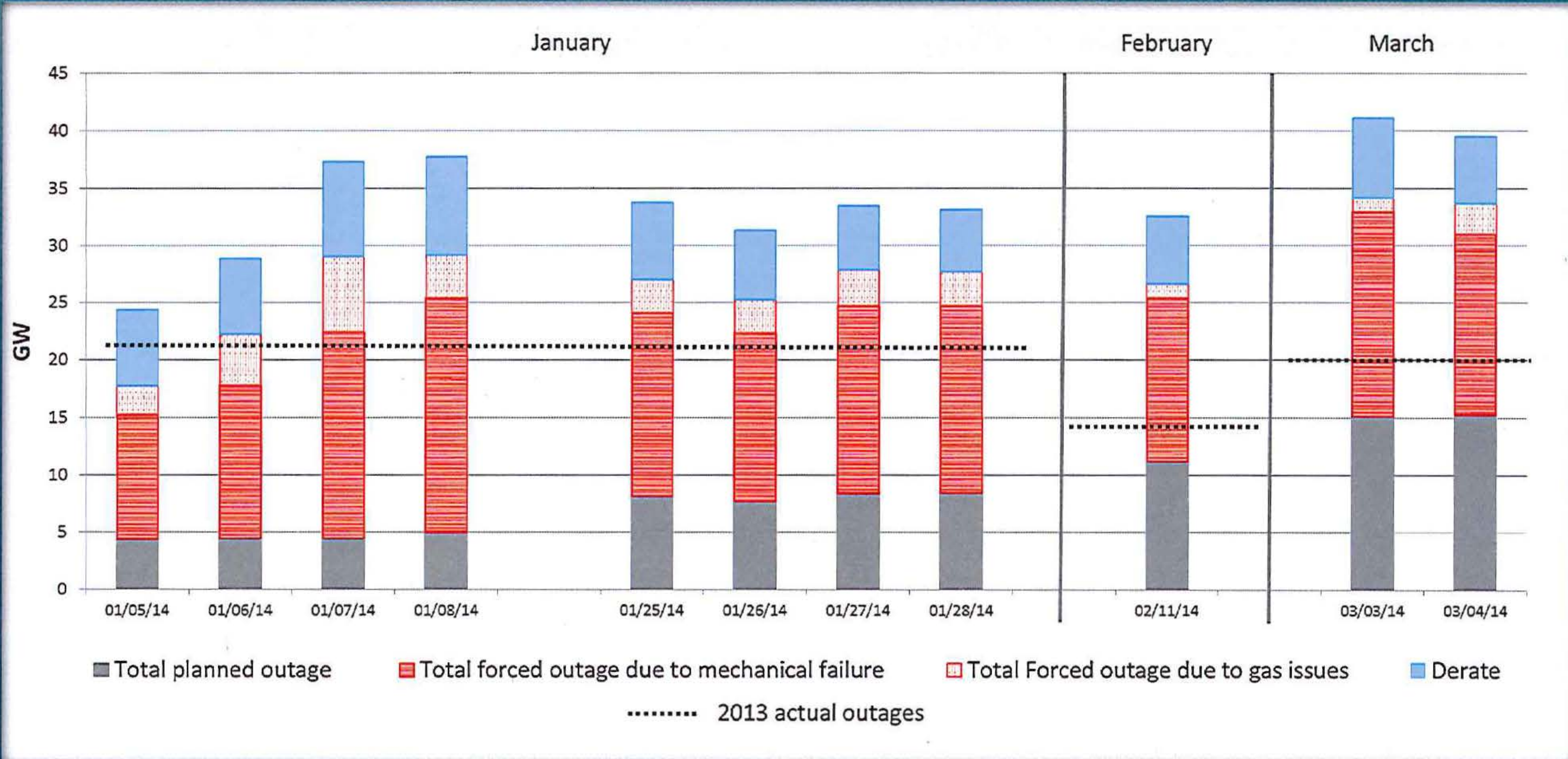
Overview

- Coldest temperatures experienced in two decades
- Successfully prepared for and managed new all-time winter market peak
- Electric/Gas Coordination Field Trial allowed for open communication
- Historic event led to key takeaways and lessons learned

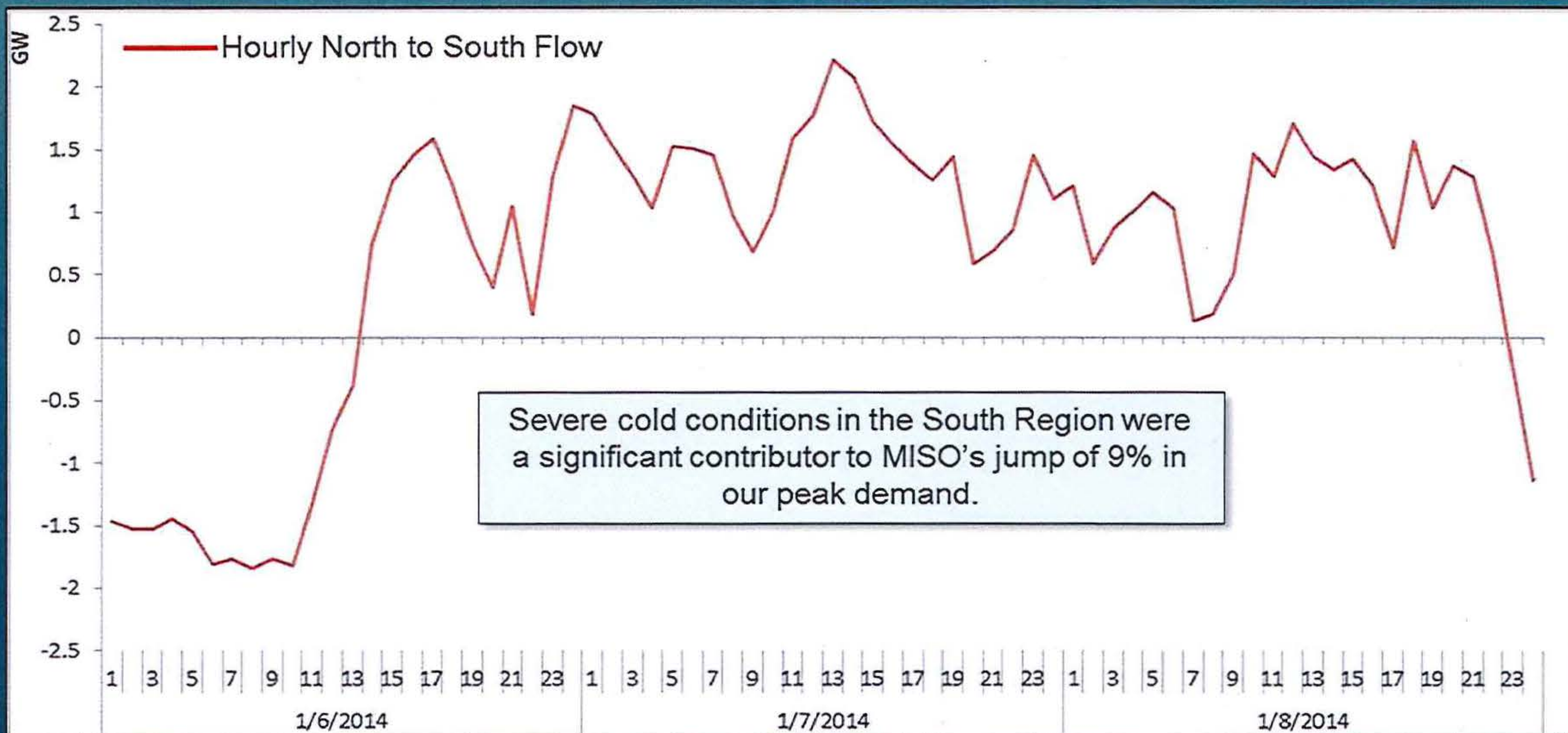
Impacts of extreme low temperatures were experienced across the entire MISO Region. Temperatures in many areas were the coldest experienced in 20 years.



The number of forced outages escalated as the severe weather conditions moved into the footprint. Freezing components and fuel restrictions caused challenges for many units.

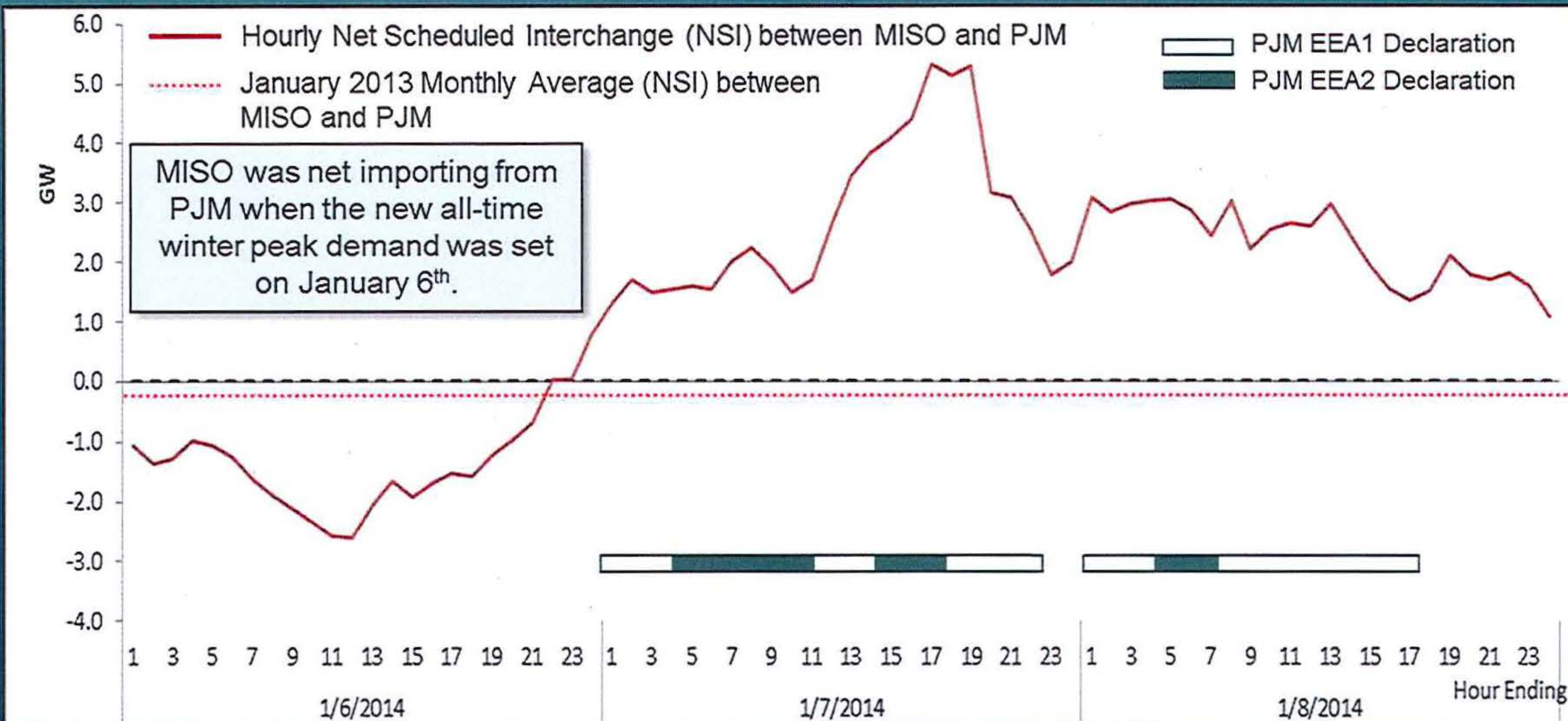


Load was able to be served broadly as flows reversed based on the low temperatures and high loads even while the South was experiencing peak conditions within their region near summer peak demands.



Negative North to South Flow means flow is from north to south

MISO experienced winter peak conditions on January 6th. Reduced peak load obligations on subsequent days freed up resources allowing MISO to assist PJM as the extreme cold temperatures moved into the East.



Negative sign of NSI between MISO and PJM means net import from PJM and positive sign indicates net export from PJM

Electric/Gas Coordination Field Trial allowed for open coordination with gas pipeline companies during these extreme weather conditions and during the TransCanada Pipeline explosion.

Provided opportunity to communicate any issues that could have impacted pipeline operations and gas flows to generation resources within our footprint

Explosion of a gas pipeline on the TransCanada Pipeline on January 25th added to the winter season's operational challenges

Extreme conditions were managed successfully due to extensive preparation and significant coordination with members and natural gas pipeline operators.

While this historic winter season was managed reliably, MISO continues to explore opportunities to improve.

Improved Coordination with the Gas Pipeline Operators through Electric-Natural Gas Coordination Task Force & on-going field trial

Substantial seasonal variation in Demand Side Resource availability

Enhance situational awareness around generation unavailability and post- analysis capabilities

Develop reliable, efficient, localized processes to manage local constraints to not unnecessarily impede regional transactions

Market Pricing, in general, was reflective of the tight operating system conditions. Need to enhance pricing to ensure demand response doesn't distort market signals.

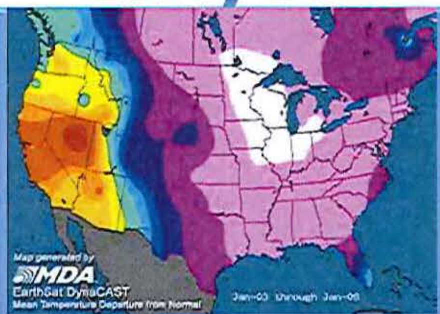
Winter 2013-2014 Operations and Market Performance in RTOs and ISOs

AD14-8-000

April 1, 2014

2014 Severe Weather Events

Jan 6-7 "Early Jan"



Jan 22 "The $100 Gas Price"

Jan 27 "Persistent Cold"

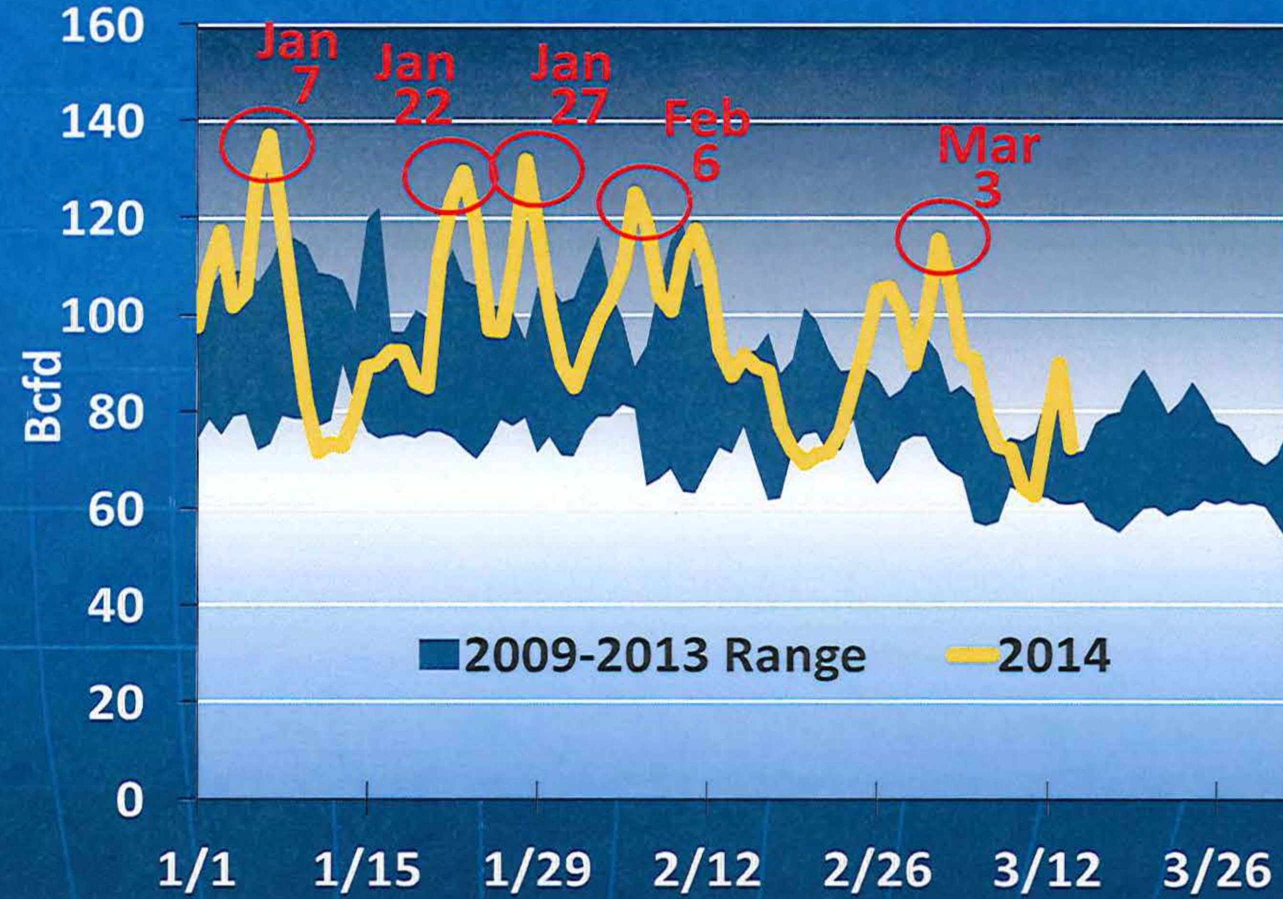
Feb 6 "West Cold"

-15	-8	-5	-3	-2	-1	0	+1	+2	+3	+5	+8	+15	°F

Strong Below	Much Below	Below	Normal	Above	Much Above	Strong Above

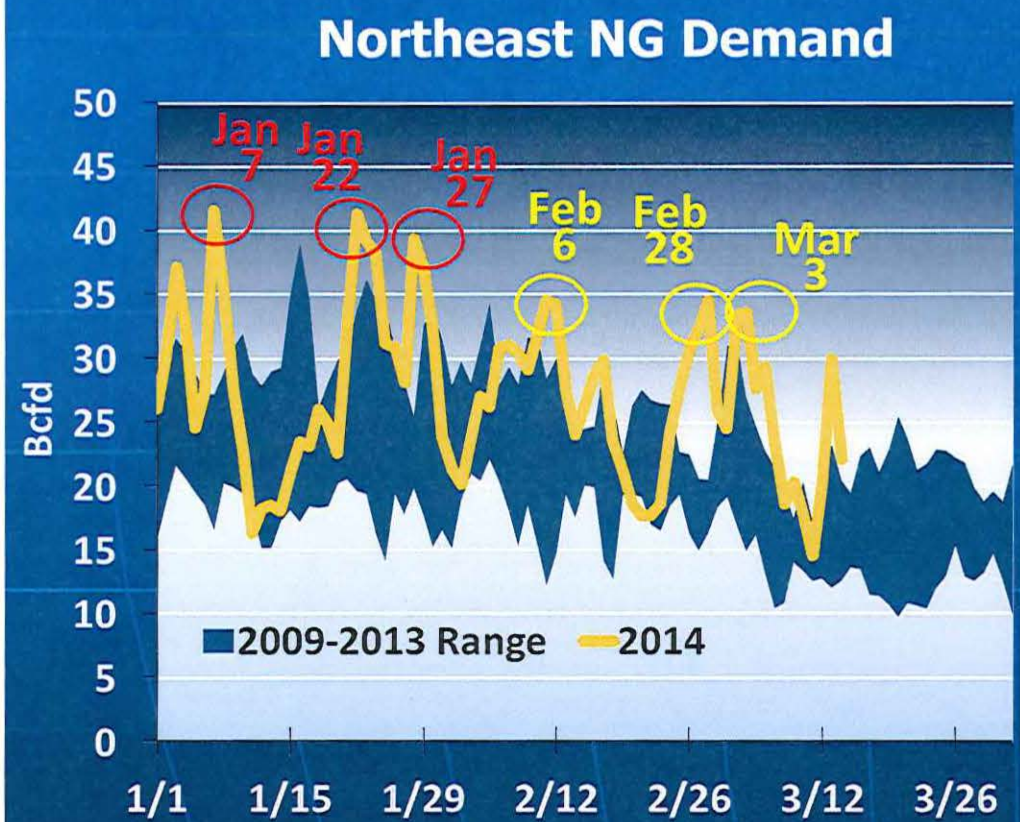
Above maps compare anomalies against a 10 year normal (2004-2013)

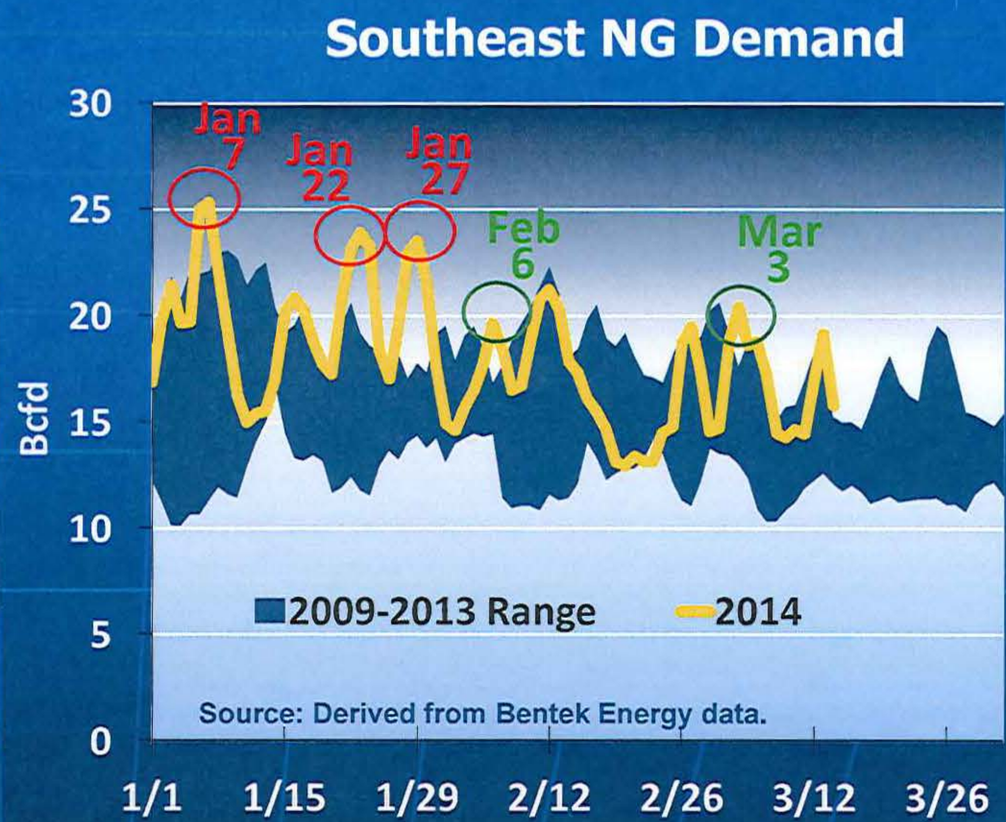
National NG Demand Soars Beyond 5-yr Averages



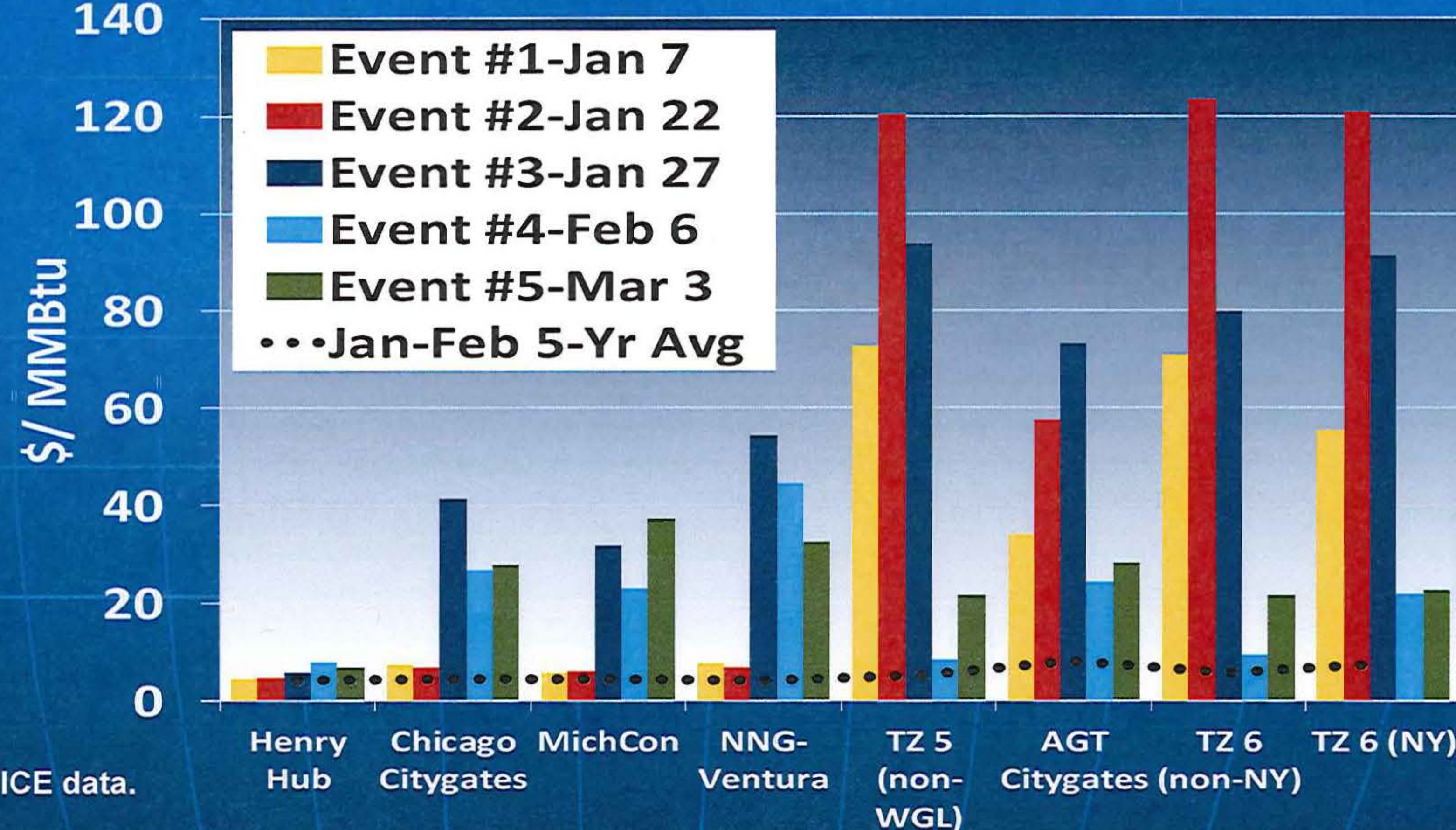
Source: Derived from Bentek Energy data.

Northeast & Southeast Peak Demand Coincides



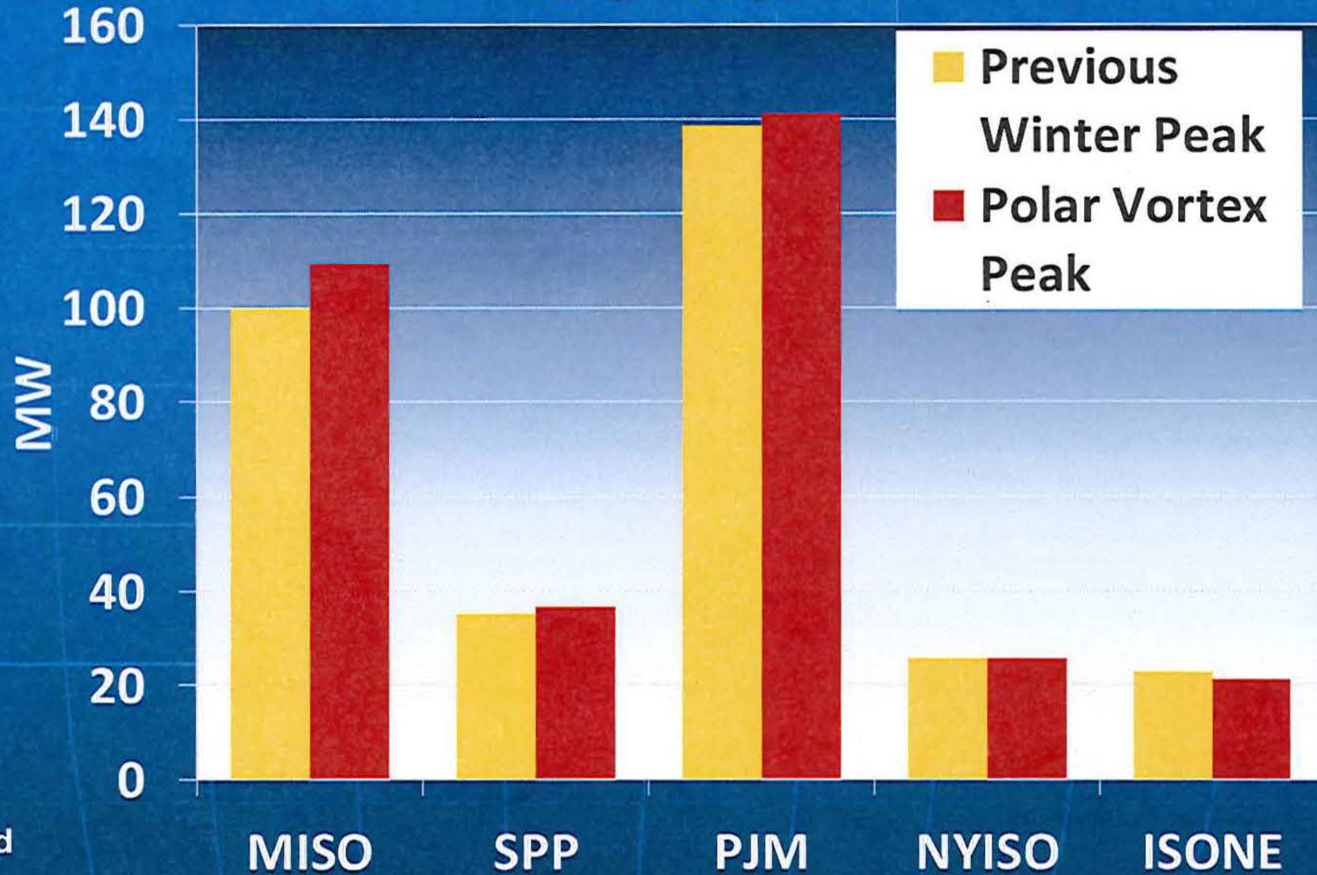


NG Prices Soar in the Eastern U.S.



Source: Derived from ICE data.

New Electric Winter Peak Demands Set During Polar Vortex



Source: Derived from ISO and RTO data.

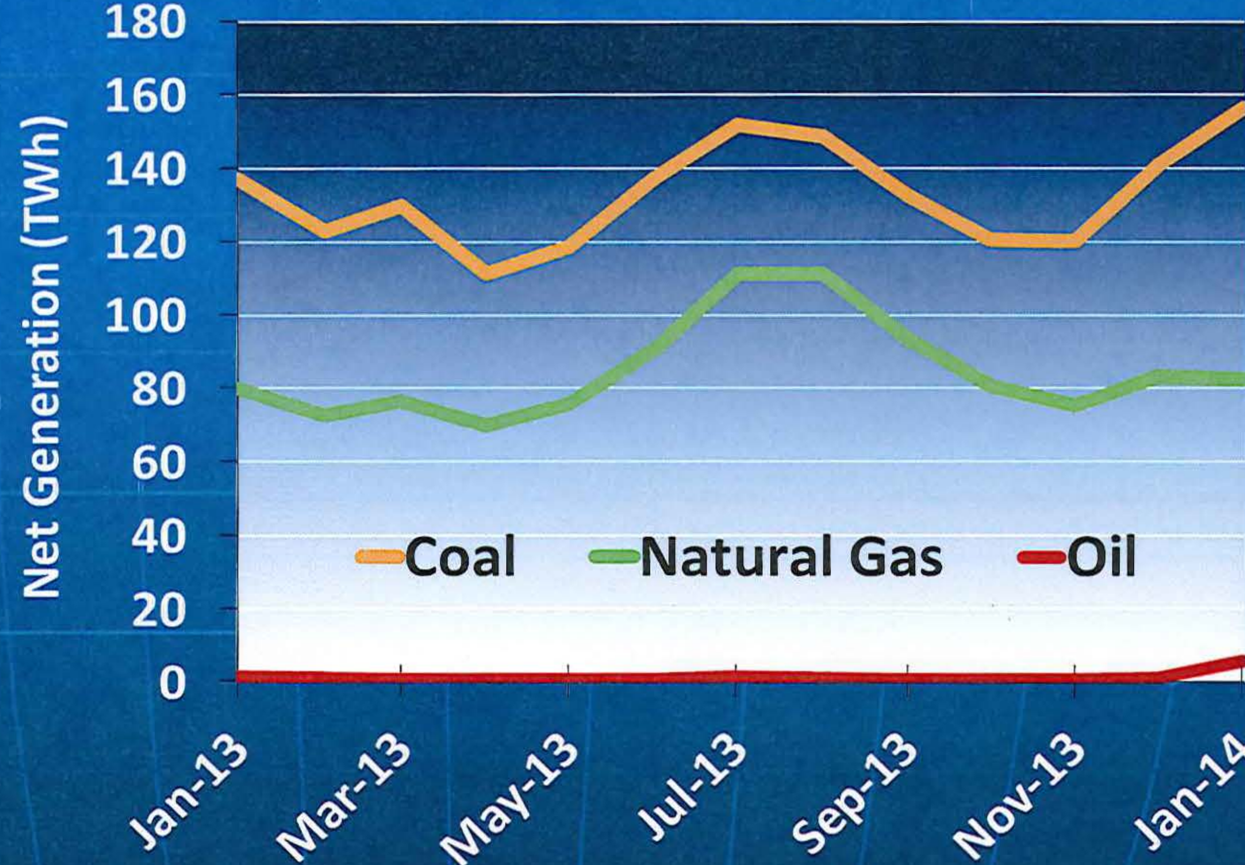
Generator Outages Add to Market Stress

Early January Peak Day Generation Outages (January 6 and 7)					
ISO	**Peak load MW**	**Lost Generation* MW**	**% of Peak**	**Fuel Supply Issues MW**	**% of Lost Generation**
PJM	141,312	41,336	29%	9,718	24%
ISONE	21,320	1,473	7%	1,473	100%
NYISO	25,738	4,135	16%	2,235	54%
MISO	107,770	32,813	30%	6,666	20%
SPP	36,602	3,185	9%	2,412	76%

*Forced outages and derates.

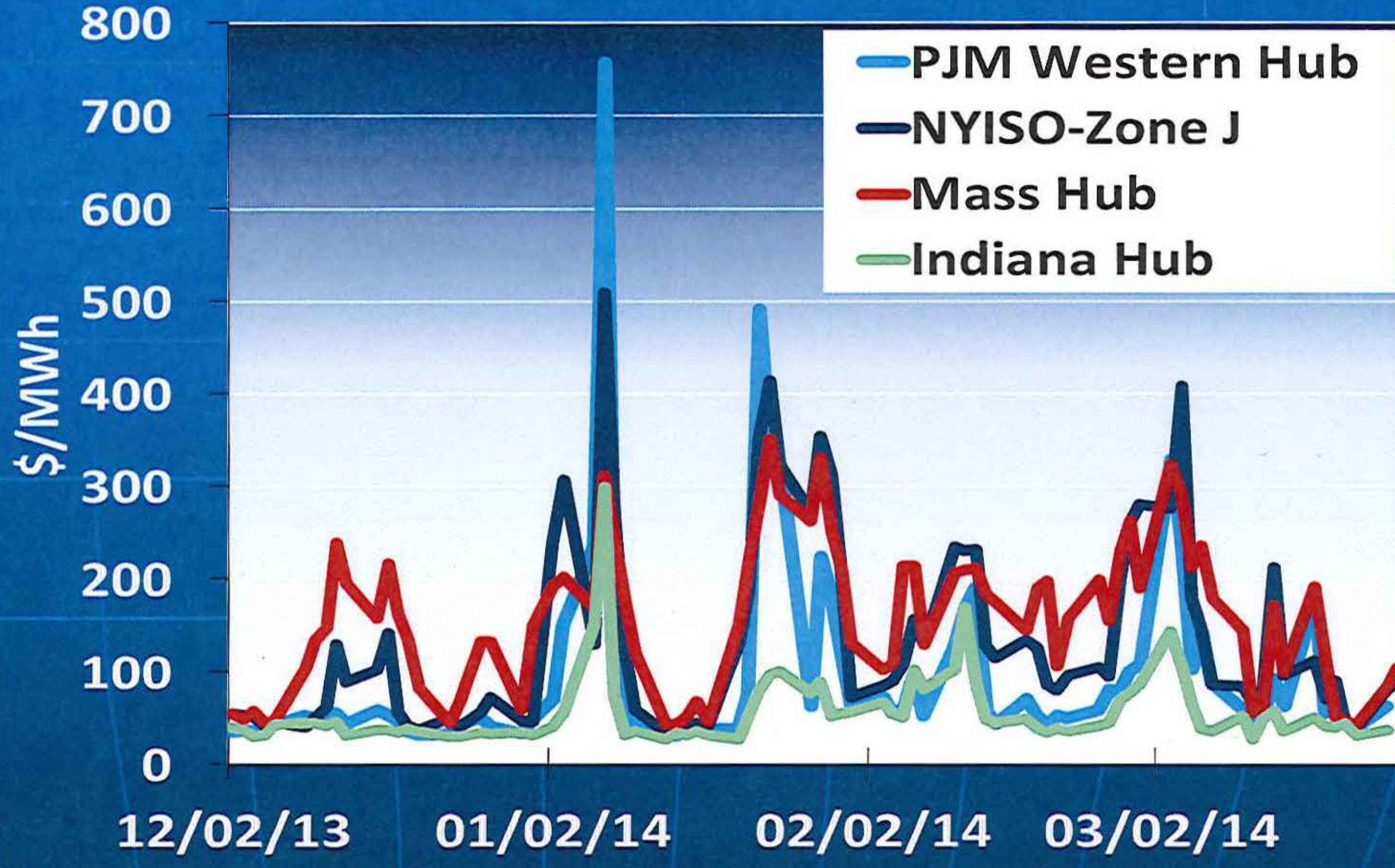
Source: RTOs and ISO.

Natural Gas Burn Dips in January



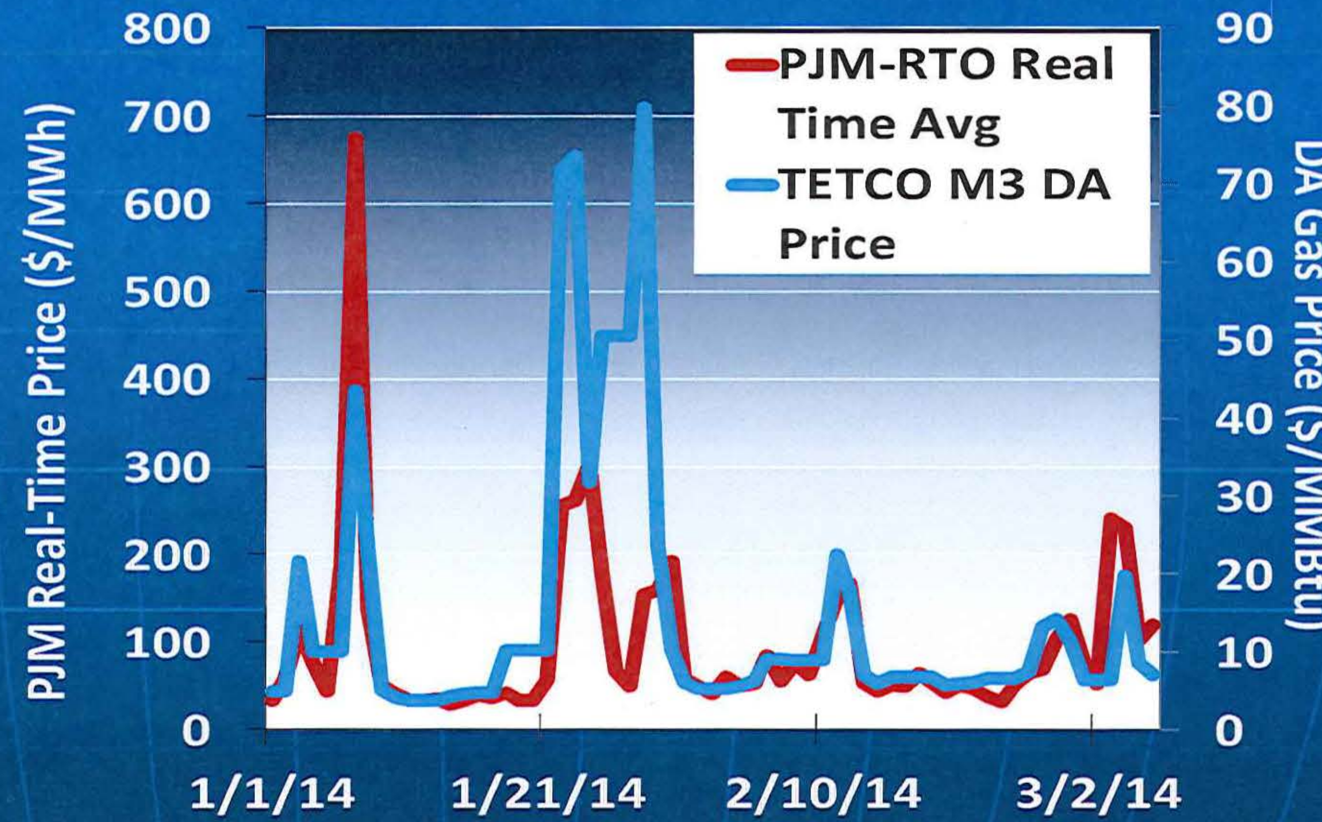
Source: Derived EIA data.

RTO and ISO Prices Winter 2014



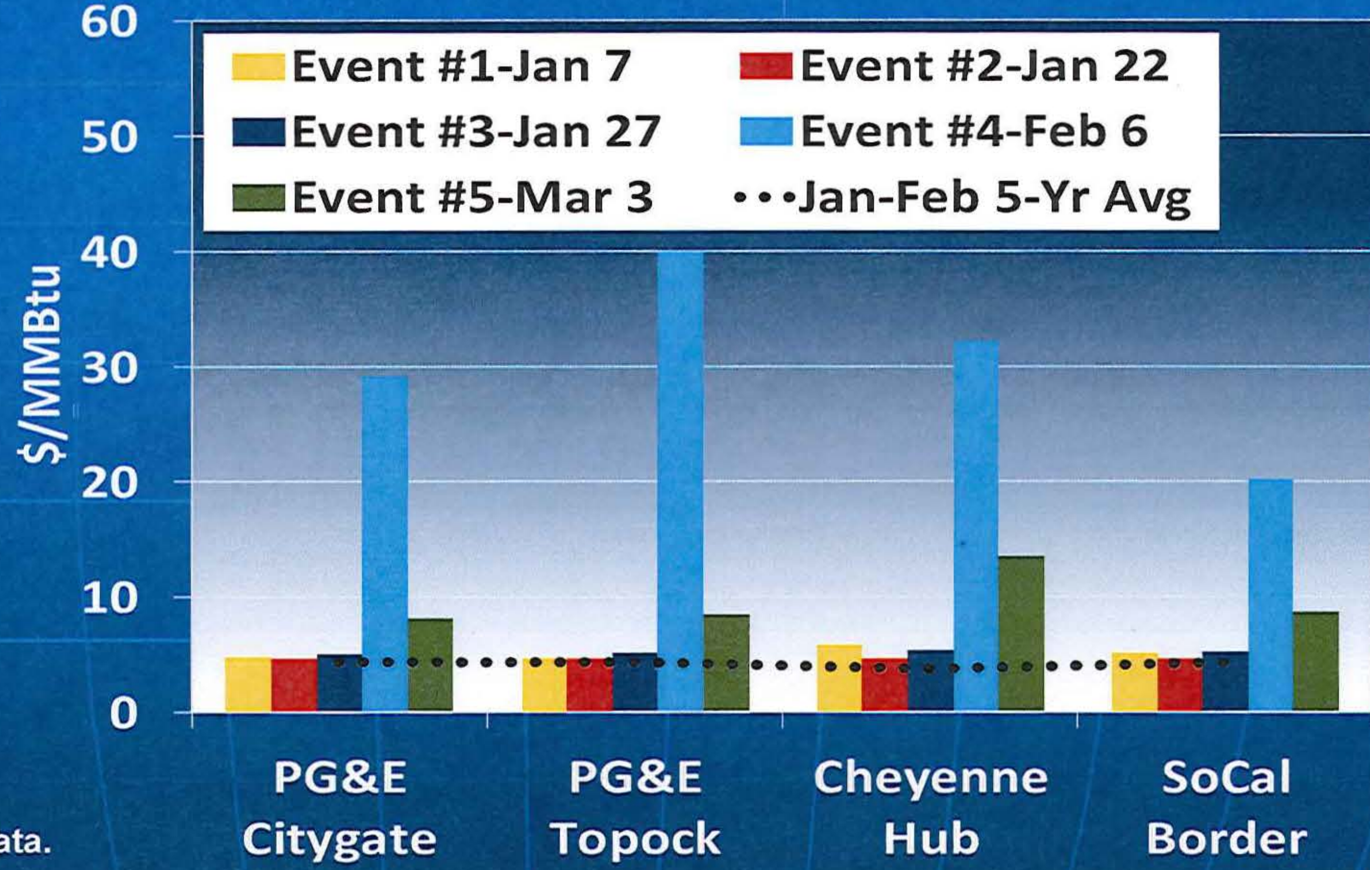
Source: Derived from Velocity Suite data.

Electricity Prices Follow Natural Gas Prices



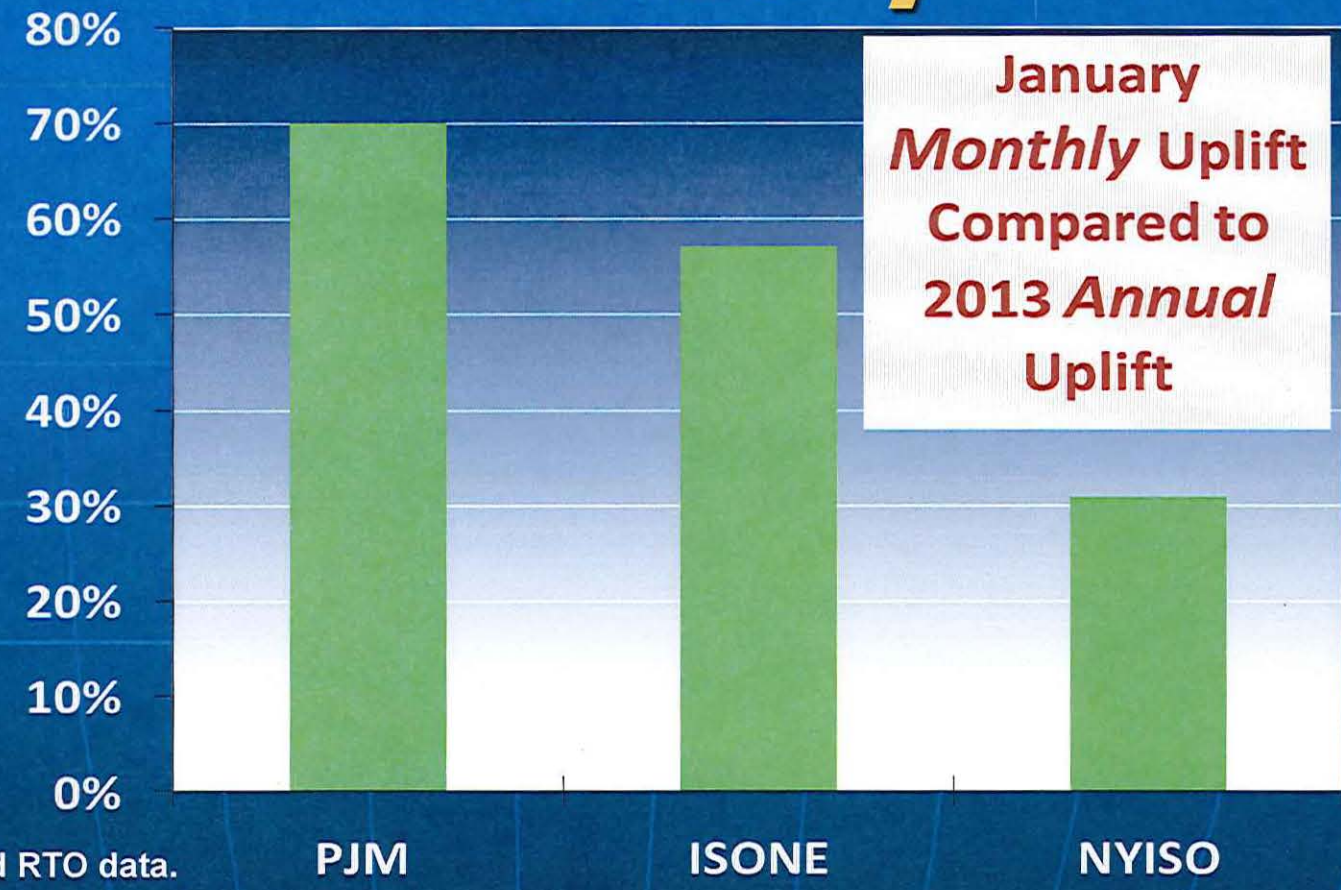
Source: Derived from Velocity Suite data.

Record NG Prices in the West



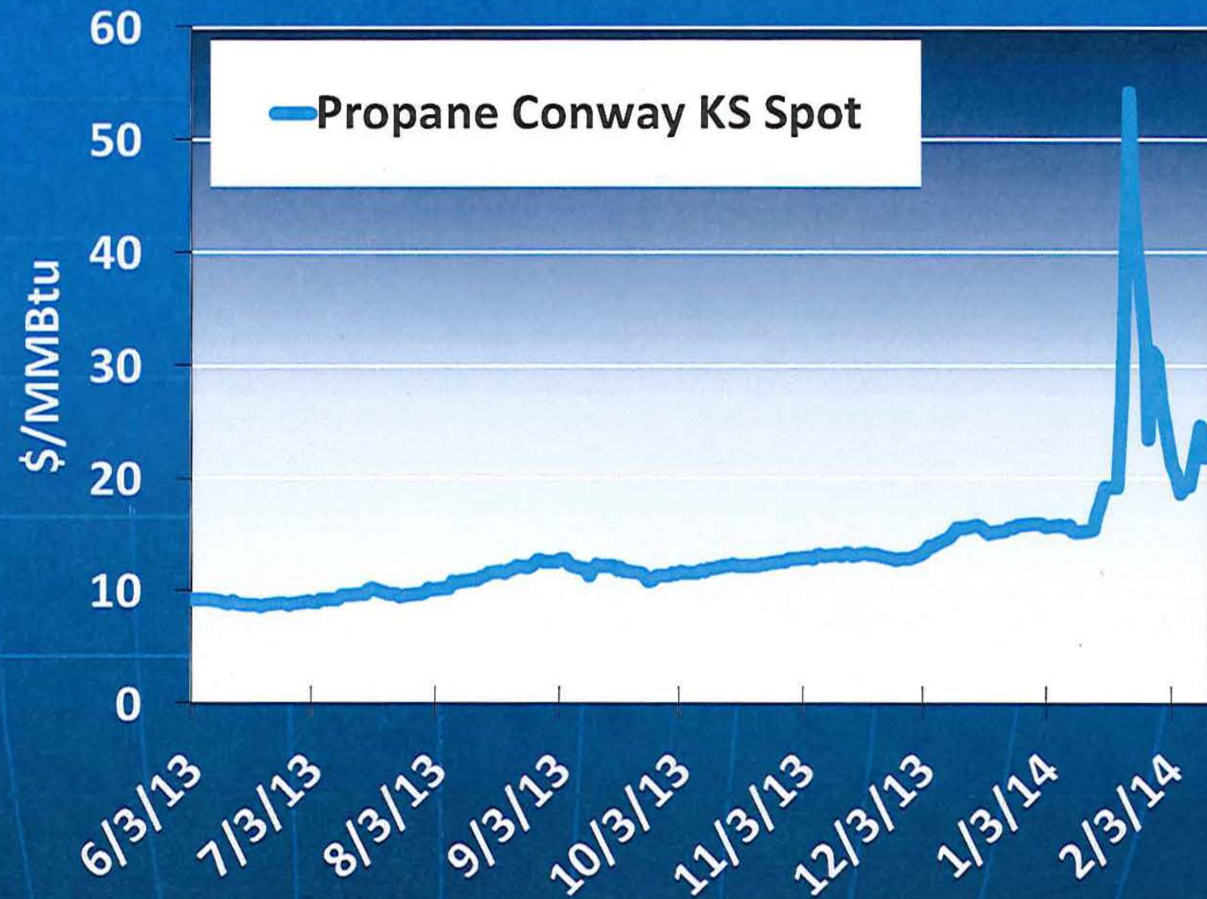
Source: Derived from ICE data.

Uplift is High in January



Source: Derived from ISO and RTO data.

Propane Price Spikes



Source: Derived from Bloomberg data.

Analytics and Surveillance Response

- Automated computer routines ("screens") that sift through both public and non-public data, such as EQR data, ISO/RTO market data, including offer, uplift, and outage data and FTR holdings, e-Tags, ICE transaction data, large trader reporting data, Form 552 data, Bentek, and Platts.
- Built by DAS staff based on:
  - ✓ Known manipulative schemes
  - ✓ Market rules
  - ✓ Behavior that could constitute manipulation if entered into
  - ✓ Statistical measures that help identify market anomalies
  - ✓ Persistence measures

Analytics and Surveillance Response

- Analysts routinely run screens and analyze the output, sharing the results with all division staff, including management.
- While DAS surveillance screens are based on different parameters and theoretical approaches, many follow a common framework composed of three building blocks:
  - Tool → Target → Benefiting Position

Analytics and Surveillance Response

- Algorithmic surveillance screens generated multiple alerts in January and February for New England, the Mid-Atlantic, the Midwest and California.
- Staff followed up on these alerts and other information it received to identify potential market misbehavior.
  - ✓ Coordinated with RTO/ISO and market monitoring staff to discuss market conditions and operations and any issues they identified related to their markets
  - ✓ Conducted dozens of interviews with generators, gas suppliers and traders to gather market insights and facts relating to operations and bidding
  - ✓ Used Order 760 datasets to gather generator uplift payments and offers
  - ✓ Used the recently received CFTC Large Trader Report data to identify financial incentives by company at volatile hubs
  - ✓ Data requests were issued to certain companies

Analytics and Surveillance Observations

- Preliminary observations:
  - ✓ Natural gas spot prices were at record levels, driven by high demand, pipeline flow restrictions, covering of physical short positions and concern for pipeline penalties .
  - ✓ Pricing issues aggravated by power users not knowing gas needs within the gas trading window and pipelines restricting hourly usage flexibility. Users reflected expectation of low Northeast basis in their supply planning (e.g., due to increased Marcellus supply and new transport).

Analytics and Surveillance Observations

- Preliminary observations:
  - ✓ Higher levels of uplift related to conservative operations and high natural gas prices
  - ✓ Unable to re-supply oil as quickly as needed due to significant oil for power generation (fewer problems in New England due to this winter's fuel program)
  - ✓ Spot market supply was reduced. Firm users were able to buy gas but certain interruptible customers (especially power peaking units) were unable to obtain gas for some periods.
- Our review is ongoing and we will report to the Commission upon completion.

Winter 2013-2014 Operations and Market Performance in RTOs and ISOs

AD14-8-000

April 1, 2014

The Information Contained in this Response has been designated as Highly Confidential

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**Ameren Missouri
Response to Noranda Data Request
MPSC Case No. EC-2014-0224
In the Matter of Noranda Aluminum, Inc.'s Request For Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.**

Data Request No.: Noranda 4-5

4.1. Please refer to Mr. Michelsâ€™ rebuttal testimony at page 30, lines 4 through 8 and 15 through 18. Assuming Ameren Missouri continues to serve Noranda, Noranda remains in full operation and no retirements of the Companyâ€™s existing generation facilities in the next 10 years, please identify the Companyâ€™s latest projection of the year in which it will need to add new generation facilities to serve its retail customers. In addition, please provide a detailed explanation of the basis of that projection and a complete copy of all analyses and studies prepared by, or on behalf of, the Company regarding that projection.

RESPONSE

**Prepared By: Matt Michels
Title: Senior Manager, Corporate Analysis
Date: May 16, 2014**

The requested analysis has not been performed.

The Information Contained in this Response has been designated as Highly Confidential

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Noranda Aluminum, Inc.'s First Set
<u>of Data Requests to Missouri Public Service Commission Staff</u>

1.2. Regardless of the response to the preceding question concerning MISO nodes, please explain in detail why these generation nodes are the relevant measure, as opposed to the AMMO.UE node.

Answer: Staff had misunderstood that these generation nodes are relevant in that the AMMO.UE Load Node is an aggregate price node per the MISO Tariff Module A Common Tariff Provisions part 1.9. Having had further discussion with Ameren Missouri, Staff has concluded that it would be more appropriate to use the AMMO.UE Load Node.