Exhibit No.:	
Issue:	Cost of Service and Rate Design
Witness:	James R. Dauphinais
Type of Exhibit:	Direct Testimony
Sponsoring Party:	MIEC
Case No.:	ER-2014-0258
Date Testimony Prepared:	December 19, 2014

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))))	**Case No. ER-2014-0258**

Direct Testimony and Schedules of

James R. Dauphinais

On behalf of

Missouri Industrial Energy Consumers

NON-PROPRIETARY VERSION

December 19, 2014

Brubaker & Associates, Inc.

Project 9913

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)	**Case No. ER-2014-0258**

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 the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.

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 18th day of December, 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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Direct 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 WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC") including Noranda Aluminum, Inc. ("Noranda"). These companies purchase substantial quantities of electricity from Ameren Missouri (or "Company").

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A Yes. I have been involved in a number of proceedings before the Commission including, but not limited to, Case Nos. ER-2007-0002, ER-2008-0318, ER-2010-0036, ER-2011-0028 and ER-2012-0166, where I testified with respect to the fuel cost, off-system sales and transmission revenues and expenses of Union Electric Company ("Ameren Missouri"). I also presented testimony in Case No. EC-2014-0224 with respect to the reduction in Actual Net Energy Cost ("ANEC") and Midcontinent Independent System Operator, Inc. ("MISO") load-based charges not included in Ameren Missouri's ANEC that Ameren Missouri would experience if Noranda's New Madrid facilities were shut down.

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CURRENT PROCEEDING?

A My direct testimony in this proceeding addresses two issues:

- Whether Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel and purchased power should be included in Ameren Missouri's Fuel Adjustment Clause ("FAC"); and
- The ANEC, and MISO load-based charges not included in Ameren Missouri's ANEC, that Ameren Missouri would avoid, based on normalized historical data, if Noranda's New Madrid facility were to shut down.

The fact that I do not address any other particular issue in this testimony should not be interpreted as an approval of any position taken by Ameren Missouri in its direct testimony.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS.

A I conclude the following:

- All of Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel or purchased power should be removed from Ameren Missouri's FAC since Section 386.266.1, RSMo (Supp. 2011) only permits the inclusion of the cost of transportation for fuel and purchased power in an FAC – not the cost of transportation of power that is not purchased power. This will remove all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses from its FAC. This adjustment will not affect Ameren Missouri's base rate revenue requirement. However, it will increase the portion of that base rate revenue requirement included in Ameren Missouri's Net Base Energy Cost ("NBEC") by approximately $7.6 million[1] based on the test year wholesale transmission revenue and expense data Ameren Missouri included in its direct case. This NBEC adjustment will need to be recalculated during the true-up phase of this proceeding due to the significant drop in MISO point-to-point transmission expenses that Ameren Missouri has seen since the December 19, 2013 integration of Entergy into MISO.[2]

- The ANEC, and MISO load-based charges not included in Ameren Missouri's ANEC, that Ameren Missouri would avoid if Noranda's New Madrid facility was shut down ranges from $28.03 to $29.39 per MWh on a normalized historical basis using the same three year averaging approach with the Polar Vortex Anomaly normalized out that Ameren Missouri, Commission Staff and MIEC used in the revenue requirement part of the case to determine off-system sales prices. The number will vary some depending on the specific method used to estimate the annual reduction.

Q YOU HAVE USED THE TERM NBEC AND ANEC. PLEASE EXPLAIN BOTH OF THOSE TERMS.

A Ameren Missouri's NBEC is its base rate revenue requirement for: (i) its expenses includable in its FAC minus (ii) its revenues that are includable in its FAC. Ameren Missouri's ANEC is its actual revenue requirement for: (i) its expenses includable in its FAC minus (ii) its revenues that are includable in its FAC. Under Ameren Missouri's current FAC (and the version of its FAC that it is proposing in this

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[1] $36.9 million in wholesale transmission revenues and 96.5% of $30.4 million in MISO wholesale transmission expenses would be removed from Ameren Missouri's NBEC.

[2] As an alternative to excluding all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses, MIEC would be amenable to excluding all of Ameren Missouri's wholesale transmission revenues and expenses from its FAC. This alternative would exclude $36.9 million in wholesale transmission revenues and $32.3 million in wholesale transmission expenses from Ameren Missouri's NBEC, which would increase Ameren Missouri's NBEC by approximately $4.6 million rather than $7.6 million.

proceeding), subject to a finding of prudence by the Commission, 95% of the difference between Ameren Missouri's ANEC and its authorized NBEC is recoverable from customers through Ameren Missouri's FAC between Ameren Missouri's base rate proceedings.

II. Inclusion of Wholesale Transmission Expenses and Revenues in Ameren Missouri's FAC

Q PLEASE DESCRIBE AMEREN MISSOURI'S WHOLESALE TRANSMISSION EXPENSES AND REVENUES.

A Ameren Missouri's wholesale transmission expenses are the transmission and non-market related ancillary service charges reflected in FERC Account 565 that Ameren Missouri incurs under the wholesale transmission tariffs of MISO and other transmission providers. Ameren Missouri incurs these expenses for three reasons:

- To transmit electric power from its own generation facilities to its own load;
- To transmit electric power it has purchased from MISO or other third-parties ("Purchased Power") to its own load; and
- To transmit electric power it is selling to third parties ("Off-System Sales") to locations outside of MISO.[3]

Ameren Missouri's wholesale transmission revenues are the transmission and non-market related ancillary service revenues reflected in FERC Account 456.1 that Ameren Missouri earns via the MISO transmission tariff. These revenues are paid to Ameren Missouri for use of its transmission system by third parties.

[3]Under the terms and conditions of the MISO transmission tariff, Ameren Missouri is not subject to any wholesale transmission charges for its off-system sales to MISO or to third-parties located inside the footprint of MISO.

Q WHY IS THE QUESTION OF WHETHER SOME OR ALL OF THESE EXPENSES AND REVENUES SHOULD BE INCLUDABLE IN AMEREN MISSOURI'S FAC A SIGNIFICANT ISSUE IN THIS PROCEEDING?

A Ameren Missouri's wholesale transmission expenses have risen and are expected to continue to rise by a large amount over the next few years without a comparable offsetting increase in its wholesale transmission revenues. This is principally due to MISO Schedule 26-A charges, which recover the cost of regionally funded Multi-Value Transmission Projects ("MVP"). The MISO Schedule 26-A rate, which was zero just four years ago, is forecasted to be $0.58 per MWh in 2015 and is forecasted by MISO to rise to $1.65 per MWh by 2021. This will cause Ameren Missouri's annual MISO Schedule 26-A charges to rise by $40 million or more from 2015 to 2021 assuming total annual MISO Schedule 26-A billing units of at least 38.8 million MWh for Ameren Missouri.[4,5] Allowing increases of these wholesale transmission expenses to flow through the FAC would allow Ameren Missouri to recover these increases between base rate proceedings without considering whether Ameren Missouri has any offsetting changes in its non-fuel revenues and expenses. This could allow Ameren Missouri to over-recover its total costs. Therefore, these wholesale transmission expenses should not be allowed to be recovered through the FAC except to the extent: (i) it is permitted by Section 386.266 and (ii) the expenses meet the standard the Commission has applied when determining the eligibility for costs to be recovered in an FAC.

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[4]Schedule JRD-1 and Ameren Missouri witness Laura Moore's Schedule LMM-17.
[5]$40 million ≈ $41.5 million = ($1.65 per MWh - $0.58 per MWh) x 38.763 million MWh.

Q WHICH WHOLESALE TRANSMISSION EXPENSES AND REVENUES MAY THE COMMISSION ALLOW TO BE INCLUDED IN AN FAC?

A The Missouri statute that authorizes the establishment of FACs, Section 386.266.1, RSMo (Supp. 2011), allows an electric utility to make periodic rate adjustments only to "reflect increases and decreases in its prudently incurred fuel and purchased power costs, including transportation." This means that the only transportation costs that can be included in an FAC are: (i) transportation costs for fuel and (ii) transportation costs for purchased power. For each wholesale transmission expense or revenue that Ameren Missouri proposes to include in its FAC, the Commission must find that it is either a transportation cost for fuel or a transportation cost for purchased power in order to be included in Ameren Missouri's FAC. However, since fuel cannot be physically transported using the electric transmission system, the only wholesale transmission expenses and revenues that can be included in the FAC are wholesale transmission expenses incurred to transport purchased power.

Q IS AMEREN MISSOURI PROPOSING TO ONLY INCLUDE IN ITS FAC WHOLESALE TRANSMISSION EXPENSES AND REVENUES THAT ARE FOR THE TRANSPORTATION OF PURCHASED POWER?

A No. Ameren Missouri is proposing to place all of its wholesale transmission expenses and revenues into its FAC, not just those that are for the transportation of purchased power. Only Ameren Missouri's wholesale transmission expenses that are incurred to transmit electric power it has purchased from MISO or other third-parties (i.e., Purchased Power) should be includable in Ameren Missouri's FAC as they are the only transportation costs for purchased power that Ameren Missouri incurs.

Ameren Missouri's wholesale transmission expenses incurred to transmit power from its own generation resources to its own load should be excluded from the FAC because these expenses are not incurred for transportation of fuel or purchased power. For the same reason, Ameren Missouri's wholesale transmission expenses incurred to transmit the electric power it is selling to third-parties (i.e., Off-System Sales) to locations outside of MISO should be excluded from the FAC along with all of its wholesale transmission revenues.

Q HAVE YOU BEEN ABLE TO CLASSIFY AMEREN MISSOURI'S WHOLESALE TRANSMISSION EXPENSES INTO THOSE TO: (I) TRANSMIT POWER FROM ITS OWN GENERATION TO ITS OWN LOAD, (II) TRANSMIT PURCHASED POWER TO ITS LOAD AND (III) TRANSMIT OFF-SYSTEM SALES?

A Yes. Table JRD-1 breaks all of Ameren Missouri's wholesale transmission expenses into each of the aforementioned categories.

TABLE JRD-1

Ameren Missouri
Wholesale Transmission Expenses Classified by Function

Function	**Wholesale Transmission Expenses**
Transmission of Power from Ameren Missouri's Generation to Ameren Missouri's Load	Nearly all of the MISO Schedule 1, 2, 9, 26, 26-A, 41 and 42-A charges incurred by Ameren Missouri for the Network Integration Transmission Service ("NITS") it takes from MISO for its load.[1]
Transmission of Purchased Power	All non-MISO wholesale transmission charges incurred by Ameren to transmit purchased power to the boundary of the MISO transmission system for ultimate delivery to Ameren Missouri's load. A very small portion of the MISO Schedule 1, 2, 9, 26, 26-A, 41 and 42-A charges incurred by Ameren Missouri for the Network Integration Transmission Service ("NITS") it takes from MISO for its load.[1]
Transmission of Off-System Sales	All MISO Schedule 1, 2, 7, 8, 26, 26-A, 33 and 45 charges incurred by Ameren Missouri for point-to-point transmission service to transmit off-system sales out of MISO to third-party buyers located outside of MISO. All non-MISO wholesale transmission charges incurred by Ameren to transmit Off-System Sales from the boundary of the MISO transmission system to third-party buyers located outside of MISO.

[1]For the NITS service it takes from MISO, Ameren Missouri pays MISO Schedule 1, 2, 9, 41 and 42-A charges for the small portion of its load served from Entergy Arkansas, Inc.'s transmission facilities. For the remainder of its load, Ameren Missouri pays MISO Schedule 26 and 26-A charges for the NITS service it takes from MISO.

In Table JRD-1, it is important to note that Ameren Missouri does not incur any wholesale transmission expenses to make off-system sales to MISO or to any third-party located within MISO. Pursuant to the MISO tariff, Ameren Missouri only incurs wholesale transmission expenses for Off-System Sales when those sales are to third-parties located outside of MISO.

Q IN TABLE JRD-1, YOU INDICATE THAT NEARLY ALL OF AMEREN MISSOURI'S MISO WHOLESALE TRANSMISSION EXPENSES ASSOCIATED WITH THE NETWORK INTEGRATION TRANSMISSION SERVICE ("NITS") IT TAKES FROM MISO TO SERVE ITS LOAD ARE FOR THE TRANSMISSION OF POWER FROM ITS OWN GENERATORS TO ITS OWN LOAD, RATHER THAN TO TRANSMIT PURCHASED POWER TO ITS OWN LOAD. PLEASE EXPLAIN HOW THE NITS AMEREN MISSOURI TAKES FROM MISO PROVIDES BOTH FUNCTIONS AND WHY NEARLY ALL OF IT IS FOR TRANSMITTING POWER FROM AMEREN MISSOURI'S OWN GENERATION TO ITS OWN LOAD.

A The NITS obtained by Ameren Missouri from MISO allows delivery of power to Ameren Missouri's load from either Ameren Missouri's own generation facilities or from third-party sources. In each operating hour, Ameren Missouri offers energy production from all of its generation facilities into the MISO market and clears all of its load in the MISO market. In an hour in which Ameren Missouri's cleared generation MWh equals its cleared load MWh, Ameren Missouri has neither any power purchases from MISO nor any off-system sales to MISO. As a result, in such hours the wholesale transmission expense for its NITS is entirely associated with the transmission of power from Ameren Missouri's own generation to its own load.

In an hour when Ameren Missouri clears more generation MWh than load MWh in the MISO market, it has an Off-System Sale to MISO for the MWh difference. However, that power sale is not transmitted pursuant to Ameren Missouri's NITS. As a result, in these hours, the wholesale transmission expense for its NITS is also entirely for the transmission of power from its own generation facilities to its own load.

Only in an hour when Ameren Missouri clears less generation MWh than load MWh does Ameren Missouri purchase any power from MISO such that a portion of its NITS expenses is incurred for the transmission of purchased power to its load. However, the MISO power purchase in these hours is limited to the difference between Ameren Missouri's cleared load MWh and its cleared generation MWh. In addition, because Ameren Missouri is generally self-sufficient for generation, during these hours, the total MISO purchased power MWh that are being transmitted to Ameren Missouri's load is much smaller than the total Ameren Missouri generation MWh that are being transmitted to Ameren Missouri's load.

Because far more often than not Ameren Missouri has an Off-System Sale to MISO rather than a power purchase from MISO, and its transmitted Power Purchase MWh is typically much smaller than its transmitted Generation MWh when Ameren Missouri does have a power purchase, only a very small portion of Ameren Missouri's MISO NITS transmission expenses can reasonably be considered to be incurred for the transmission (i.e., transportation) of Purchased Power. Nearly all of them are for the transportation of power from Ameren Missouri's own generation facilities to its own load and, thus, should not be recoverable in the FAC.

Q HAVE YOU BEEN ABLE TO QUANTIFY THE VERY SMALL PORTION OF AMEREN MISSOURI'S MISO WHOLESALE TRANSMISSION EXPENSES FOR NITS THAT REASONABLY CAN BE CONSIDERED TRANSPORTATION OF PURCHASED POWER?

A Yes. My Schedule JRD-2 provides Ameren Missouri's total annual MWh of generation, purchases, off-system sales and load as reported in Ameren Missouri witness Mark Peters' workpapers. Ameren Missouri's total load for which NITS service is being taken is equal to 38.763 million MWh. However, only 1.348 million MWh of that 38.763 million MWh of load was supplied from purchased power. The remaining 37.415 million MWh of load are being served by Ameren Missouri's own generation facilities. Thus, only a very small portion, approximately 3.5% (1.348 million MWh / 38.763 million MWh), of Ameren Missouri's total MISO wholesale transmission expenses incurred for NITS reasonably can be reasonably classified as being for transportation of fuel or purchased power. The other 96.5% of Ameren Missouri's total MISO wholesale transmission expenses incurred for NITS should be classified as being for the transportation of power from Ameren Missouri's own generation to its own load and excluded from the FAC and the NBEC portion of Ameren Missouri's base rate revenue requirement.

Q ARE ANY OTHER PORTIONS OF AMEREN MISSOURI'S MISO WHOLESALE TRANSMISSION EXPENSES RELATED TO THE TRANSPORTATION OF PURCHASED POWER TO ITS LOAD?

A No. All of Ameren Missouri's non-NITS related MISO wholesale transmission expenses are incurred to transmit (i.e., transport) power from its generation to third-parties located outside of MISO (i.e., to transmit off-system sales). These costs should be excluded in their entirety from Ameren Missouri's FAC and the NBEC portion of its base rate revenue requirement.

However, based on my review of Ameren Missouri witness Laura Moore's wholesale transmission expense workpapers and the MISO transmission settlement spreadsheets Ameren Missouri has provided in response to data requests, it does not appear it is readily possible to split certain MISO wholesale transmission expenses (specifically, MISO Schedule 26-A charges) between Ameren Missouri's MISO point-to-point transmission service for off-system sales and Ameren Missouri's MISO NITS service for its load. This said, the magnitude Ameren Missouri's MISO point-to-point transmission expenses have significantly fallen since the December 19, 2013 integration of Entergy into MISO since this integration eliminated the need for Ameren Missouri to take point-to-point transmission service to make off-system sales to third-parties located on the Entergy transmission system. As a result, Ameren Missouri's point-to-point MISO wholesale transmission expenses are no longer large enough to make it productive to separate them from Ameren Missouri's NITS MISO wholesale transmission expenses. Therefore, MIEC is willing to agree, for purposes of this proceeding only, to forgo trying to split them and instead proposes to estimate Ameren Missouri's total wholesale transmission expenses for the transmission of purchased power as 3.5% of all of Ameren Missouri's MISO wholesale transmission expenses rather than just 3.5% of Ameren Missouri's MISO NITS wholesale transmission expenses. However, MIEC reserves the right in future base rate proceedings to seek to split Ameren Missouri's total MISO wholesale transmission expenses between point-to-point and NITS service.

Q HAVE YOU QUANTIFIED THE 3.5% PORTION OF AMEREN MISSOURI'S MISO WHOLESALE TRANSMISSION EXPENSES THAT IS THE ONLY PORTION OF THOSE EXPENSES THAT INVOLVES THE TRANSMISSION OF PURCHASED POWER?

A Yes. For the test period data that Ameren Missouri included in its direct case, there are total wholesale transmission expenses of approximately $32.3 million (Schedule LMM-17 at Line 19). Based on my review of Ms. Moore's workpapers, approximately $30.4 million of this $32.3 million amount is for MISO wholesale transmission expenses. 3.5% of $30.4 million is approximately $1.1 million. Therefore, I estimate that only $1.1 million of Ameren Missouri's total MISO wholesale transmission expenses of $30.4 million is for the transmission of purchased power. The remaining $29.3 million of Ameren Missouri's MISO wholesale transmission expenses is for the transmission of power from Ameren Missouri's own generation to its own load or for the transmission of Ameren Missouri's off-system sales. These estimates should be refreshed during the true-up portion of this proceeding to fully reflect the large drop in MISO point-to-point transmission charges that Ameren Missouri has experienced since Entergy's integration in MISO.

Q HAVE YOU BEEN ABLE TO IDENTIFY WHICH OF AMEREN MISSOURI'S <u>NON-MISO</u> WHOLESALE TRANSMISSION EXPENSES ARE FOR TRANSMISSION OF PURCHASED POWER TO THE MISO BORDER FOR ULTIMATE DELIVERY TO AMEREN MISSOURI'S LOAD, VERSUS TRANSMISSION OF OFF-SYSTEM SALES FROM THE MISO BORDER TO THIRD-PARTIES LOCATED OUTSIDE OF MISO?

A No, I have not been able to do so. However, based on the data provided by Ameren Missouri in Ms. Moore's wholesale transmission expense workpapers, in total, these non-MISO wholesale transmission expenses amount to only $1.9 million (approximately 5.9%) of Ameren Missouri's total wholesale transmission expenses of $32.3 million. As a result, MIEC is willing to agree, for purposes of this proceeding only, to forgo trying to split them and instead proposes to allow classification of all of Ameren Missouri's non-MISO wholesale transmission expenses as being a cost for the transmission of purchased power. However, MIEC reserves the right in future base rate proceedings to seek to split these expenses into transmission for off-system sales and transmission for purchased power.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO THE ISSUE OF WHICH WHOLESALE TRANSMISSION EXPENSES AND REVENUES SHOULD BE INCLUDABLE FOR RECOVERY IN AMEREN MISSOURI'S FAC.

A I recommend the Commission exclude from Ameren Missouri's FAC and, as a result, from the NBEC portion of its base rate revenue requirement: (i) all of Ameren Missouri's wholesale transmission revenues and (ii) 96.5% of its total MISO wholesale transmission expenses. None of these wholesale transmission expenses and revenues are incurred for the transportation of fuel or the transportation of purchased power. Using the test year data presented in Ameren Missouri's direct case, these recommended exclusions will reduce the wholesale transmission revenues included in Ameren Missouri's NBEC by $36.9 million and reduce the wholesale transmission expenses included in the NBEC by $29.3 million. Therefore, the net impact on Ameren Missouri's NBEC will be to increase it by $7.6 million. However, all of Ameren Missouri's wholesale transmission revenues and 96.5% of its total MISO wholesale transmission expenses would be excluded from its FAC.

Provided Ameren Missouri reasonably can demonstrate with evidence that they are expenses that meet the past standards the Commission has used to determine the eligibility for costs to be included in a FAC, I recommend the Commission allow Ameren Missouri to include in its FAC and the NBEC portion of its base rate revenue requirement: (i) all of its non-MISO wholesale transmission expenses and (ii) 3.5% of Ameren Missouri's total MISO wholesale transmission expenses.[6] This is a reasonable estimate of the portion of Ameren Missouri's total wholesale transmission expenses and revenues that can be reasonably considered to be for the transportation of purchased power to Ameren Missouri's load. I estimate that these wholesale transmission expenses amount to approximately $3.0 million.[7]

[6] Ameren Missouri has provided no such evidence in its direct testimony. Specifically, it has not provided evidence that these expenses are: (i) large enough to present a threat to its financial wellbeing, (ii) volatile and (iii) cannot be reasonably managed by Ameren Missouri. If Ameren Missouri has any such evidence, it should be required to provide it in testimony and other parties, including MIEC, should be afforded the right to respond to that evidence with their own testimony.

[7] $3.0 million = $1.9 million + 3.5% x $30.4 million.

III. Estimate of the ANEC and Non-ANEC Load-Based MISO Charges Avoided by Ameren Missouri if Noranda's New Madrid Facilities Shut Down

Q WHAT IS THE PURPOSE OF YOUR ESTIMATE OF THE ANEC AND NON-ANEC LOAD-BASED MISO CHARGES THAT WOULD BE AVOIDED BY AMEREN MISSOURI IF NORANDA'S NEW MADRID FACILITIES WERE SHUT DOWN?

A The purpose of my estimate is to provide an avoided cost benchmark that the Commission can use to test the reasonableness of the electric rate being proposed for Noranda in this proceeding. If Noranda's New Madrid's facilities were to shut down, Ameren Missouri would lose all electric revenues from Noranda. This loss of electric revenues would be partially offset by a reduction in Ameren Missouri's ANEC[8] and a reduction of its load-based MISO charges that are not included in its ANEC. These avoided costs that partly offset the loss in revenue from Noranda are composed of the following four components:

- The increase in off-system sales revenues that would result from the loss of the Noranda load;
- The decrease in purchased power costs that would result from the loss of the Noranda load;
- The decrease in MISO wholesale transmission expenses (associated with the NITS Ameren Missouri takes from MISO) that would result from the loss of the Noranda load; and
- The decrease in load-based MISO administration charges that would result from the loss of the Noranda load.

The first two of these components will result in a reduction in Ameren Missouri's ANEC. The fourth component will result in a reduction of Ameren

[8]As discussed earlier in my testimony, ANEC (Actual Net Energy Cost) is Ameren Missouri's actual revenue requirement for: (i) its expenses that are includable in its FAC minus (ii) its revenues includable in its FAC. NBEC (Net Based Energy Cost) is Ameren Missouri's base rate revenue requirement for: (i) its expenses that are includable in its FAC minus (ii) its revenues includable in its FAC. Subject to a determination of prudency by the Commission, 95% of the difference between Ameren Missouri's ANEC and Ameren Missouri's NBEC is recoverable from Ameren Missouri's customers between Ameren Missouri's base rate proceedings.

Missouri's load-based MISO charges that are not included in its ANEC. If Ameren Missouri's position that all of its wholesale transmission charges associated with the NITS it takes from MISO should be includable in its FAC, the third of the above components will result in an additional reduction in Ameren Missouri's ANEC. If MIEC's position that nearly all of these wholesale transmission expenses should not be includable in Ameren Missouri's FAC prevails, the fourth component will nearly entirely result in an additional reduction in Ameren Missouri's load-based MISO charges that are not included in its ANEC rather than result in an additional reduction in Ameren Missouri's ANEC.

Since Ameren Missouri already makes off-system sales to MISO during most hours of the year, the first of the four components, the increase in off-system sales revenues that would result from the loss of the Noranda load, will be by far the largest of the four. Thus, the principal offsetting effect of the loss of the Noranda load would be an increase in off-system sales revenues, which will cause a reduction in Ameren Missouri's ANEC.

Q WHAT IS YOUR ESTIMATE OF THE REDUCTION IN ANEC AND NON-ANEC LOAD-BASED MISO CHARGES THAT AMEREN MISSOURI WOULD EXPERIENCE IF NORANDA'S NEW MADRID FACILITIES WERE TO SHUT DOWN?

A Using a 36-month average, and normalizing out the effect of the early 2014 Polar Vortex Anomaly, I estimate Ameren Missouri's ANEC and non-ANEC load-based MISO charges would be reduced by between $28.03 and $29.39 per MWh of reduced retail sales to Noranda. The precise number depends on the specific method used to estimate the reduction. Each of the avoided cost estimates that contribute to this range are presented in detail in Schedules JRD-3 through JRD-5.

The lower end of the range of my estimate, which is summarized in the first column of Schedule JRD-3 and presented in detail in Schedule JRD-4, is based on the same method I used in my surrebuttal testimony in Case No. EC-2014-0224. It essentially uses the same historical market price data normalization method that has been used in recent Ameren Missouri rate cases (and is proposed to be used by Ameren Missouri, Staff and MIEC in this proceeding to set the NBEC value for this FAC), but is modified to include my estimate of the impact of the reduction of market prices and a reduction in Ameren Missouri's MISO Auction Revenue Right ("ARR") revenues that would result from a shutdown of the Noranda's facility.

The upper end of this range, which is summarized in the second column of Schedule JRD-3 and presented in detail in Schedule JRD-5, is based on application of the NBEC historical market price data normalization method without the inclusion of the market price reduction and ARR revenue loss effects.

Q WHAT WOULD THE AVOIDED COST BE IF IT WERE BASED ON THE HISTORICAL MARKET PRICE NORMALIZATION METHOD PRESENTED BY STAFF WITNESS SARAH KLIETHERMES IN HER TESTIMONY IN CASE NO. EC-2014-0224?

A Ms. Kliethermes' Case No. EC-2014-0224 method develops historical market prices by averaging 48 months of market prices <u>without</u> removing any market anomalies such as the Polar Vortex Anomaly of January through March 2014. This approach would produce an avoided cost of $31.74 MWh as summarized in the third column of Schedule JRD-3 and presented in detail in Schedule JRD-6. Ms. Kliethermes' Case

No. EC-2014-0224 method deviates from the NBEC historical market price normalization method that uses a 36-month average of market prices with severe market anomalies such as the Polar Vortex Anomaly removed.

Q WHICH APPROACH DO YOU BELIEVE IS MOST REASONABLE?

A I continue to believe the method I used in my surrebuttal testimony in Case No. EC-2014-0224 is the most accurate method because it: (i) is consistent with the NBEC historical market price normalization method that Ameren Missouri, Staff and MIEC all agree on for the determination of Ameren Missouri's NBEC in this case and (ii) appropriately includes the reduction in Ameren Missouri ARR revenues and the impact of the small reduction in market prices that will result from a shutdown of the Noranda facility. This method yielded an avoided cost of $28.03 per MWh of reduced retail sales to Noranda.

In the event the Commission declines to accept the ARR revenue and market price reduction impacts incorporated in my avoided cost estimate that is based on the method I used in my Case No. EC-2014-0224 surrebuttal testimony, for consistency in ratemaking, I recommend that the Commission use my avoided cost estimate based on the NBEC market price normalization method without the ARR revenue and market price impacts. This alternative method yielded an avoided cost of $29.39 per MWh of reduced retail sales to Noranda.

Q PLEASE EXPLAIN HOW YOU DEVELOPED YOUR AVOIDED COST ESTIMATES.

A I used test year electric sales to Noranda of approximately 4,198,453 MWh per year with a load factor of 98% and a coincidence factor of 100%. I grossed these billing units up for the Associated Electric Cooperatives, Inc. ("AECI") 3.5% loss factor that is applicable under Noranda's transmission service agreement with AECI.

I next made a simplifying assumption that market clearing prices in the MISO (including Locational Marginal Prices) would remain the same or decrease slightly due to the loss of these retail sales by Ameren Missouri. I then estimated the annual dollars Ameren Missouri would avoid by not having to clear these retail sales in the market along with avoided transmission settlements with MISO. In doing so, I used recent historical MISO market clearing prices at the AMMO.UE load zone (either using the NBEC market price normalization method or Ms. Kliethermes' market price normalization method from Case No. EC-2014-0224), Ameren Missouri's recent historical MISO settlement charges and the current forecasted regional transmission charge rates for 2015 under the MISO Tariff. The details of my calculations are presented in Schedules JRD-4 through JRD-9.

Q DID YOU PERFORM ANY PRODUCTION COST SIMULATIONS TO DEVELOP YOUR ESTIMATE?

A No. Because of Ameren Missouri's participation in the MISO market and my use of reasonable simplifying assumption that market clearing prices in the MISO (including Locational Marginal Prices) would remain the same or decrease slightly due to the loss of these retail sales by Ameren Missouri, it was not necessary to use production cost simulations to estimate the reduction in ANEC and non-ANEC load-based MISO charges that Ameren Missouri would experience from the loss of its retail sales to Noranda. It can instead be estimated by applying normalized recent historical MISO market prices at the AMMO.UE load zone, Ameren Missouri's recent historical MISO settlement charges and current forecasted MISO regional transmission rates for 2015 to the MW and MWh sales to Noranda.

Q PLEASE EXPLAIN WHY THIS IS SO.

A As a participant in the MISO Regional Transmission Organization ("RTO"), Ameren Missouri must clear all of its generation and all of its load in the MISO market. Ameren Missouri's generation clears in the MISO market based on the offer price it submits for each of its generators to produce energy (or provide capacity) and the market prices set by MISO. Those market prices are set by MISO based on: (i) the generation offers of Ameren Missouri and all other MISO market participants; and (ii) the total load within the MISO market that needs to be served. As a result, the clearing of Ameren Missouri's generation facilities in the MISO market (including the commitment and dispatch of those generation facilities) would not be affected by Ameren Missouri's loss of retail sales to Noranda unless MISO market prices changed enough to influence that clearing.

Because the loss of Ameren Missouri's retail sales to Noranda would negligibly affect MISO market clearing prices in most hours of the year and act to lower those prices when there is more than a negligible effect, it reasonably can be assumed that Ameren Missouri's market settlements for its generation facilities would only be reduced by a limited amount by the loss of those retail sales. Thus, the reduction in Ameren Missouri's ANEC reasonably can be estimated as the cost avoided by Ameren Missouri by not having to clear the Noranda retail sales in its MISO market plus transmission settlements for its load. This can be calculated using normalized recent historical MISO market prices, Ameren Missouri's recent historical

MISO settlement charges and current forecasted regional transmission rates for 2015 under the MISO Tariff.

Q CAN YOU PROVIDE A SIMPLE EXAMPLE?

A Yes. Let us examine a simple example (that neglects transmission losses) involving the energy market in a single hour. Assume a utility has a retail load in this hour of 1,000 MW and the utility is participating in an RTO energy market that has a total load of 20,000 MW in this hour. Further, assume the utility has a single 1,000 MW generator that it is offering into the RTO market at $20 per MWh based on the fuel cost of that generation. Finally, assume that based on its 20,000 MW total load in that hour, the generation offer from the utility and the generation offers it receives from other market participants, the RTO sets the clearing price for energy (or Locational Marginal Price) in that hour at $30 per MWh and there is no transmission congestion in that hour.

Under these assumptions, the utility's generation facility would be fully dispatched (i.e., cleared) in that hour at 1,000 MW since its offer price of $20 per MWh is less than the Locational Marginal Price of $30 per MWh. In addition, the utility will in this hour have neither purchased energy costs nor off-system energy sales revenues since in this hour the utility's cleared generation (1,000 MW) equals its cleared load (1,000 MW).

The utility's resulting generation settlements in that hour would be as follows:

RTO Generation Revenue = 1,000 MWh x $30 per MWh = $30,000

The utility's load settlements in that hour would be:

RTO Load Expense = 1,000 MWh x $30 per MWh = $30,000

The utility's fuel cost for its generation facility would be:

Generation Fuel Cost = 1,000 MWh x $20 per MWh = $20,000

The utility's Net Fuel Cost (generation fuel cost plus purchased energy cost less off-system energy sales revenues) in that hour would be:

Generation Fuel Cost	$20,000
plus RTO Load Expense	$30,000
less RTO Generation Revenue	<u>$30,000</u>
Net Fuel Cost	$20,000

Now, assume the utility had 100 MWh lower retail sales in that hour. Also, assume the resulting 100 MWh drop of the RTO's total load in that hour from 20,000 MWh to 19,900 MWh did not change the $30 per MWh LMP in that hour. In this case, the utility's generation would still be fully dispatched at 1,000 MW of output because its $20 per MWh offer price is still less than the $30 per MWh LMP. As a result, the utility's MISO generation revenue of $30,000 and generation fuel cost of $20,000 would remain unchanged despite the utility losing 100 MWh of retail sales. The only thing that would change is that the utility will clear 900 MWh of retail load rather than 1,000 MWh of retail load in the RTO market. The utility will continue to have no purchased energy cost, but will now have a 100 MWh off-system energy sale because in this hour it is clearing 1,000 MWh of generation but only clearing 900 MWh of retail load. Thus, the utility's load settlement in the RTO market for this hour will become:

RTO Load Expense = 900 MWh x $30 per MWh = $27,000

And, the utility's Net Fuel Cost in this hour will become:

Generation Fuel Cost	$20,000
plus RTO Load Expense	$27,000
less RTO Generation Revenue	$30,000
Net Fuel Cost	$17,000

This is a $3,000 reduction in the utility's Net Fuel Cost for the hour that results from the utility's loss of 100 MWh of retail sales in that hour in this example. In the utility's accounting in this example, the $3,000 amount would appear as $3,000 of additional off-system energy sales margins reducing its ANEC. Overall, the utility would experience a drop in retail revenue or a result of the retail load loss, offset by the $3,000 gain in off-system sales margins.

Q WOULD THE NET FUEL COST SAVINGS ALWAYS APPEAR AS AN INCREASE IN OFF-SYSTEM ENERGY SALES MARGINS FOR THE UTILITY?

A No. In my example, off-system energy sales increased by 100 MWh. If the same retail sales reduction in another hour decreased the utility's purchase of energy by 100 MWh, the net fuel cost savings would appear in the utility's accounting as a reduction in the utility's purchased energy costs rather than an increase in the utility's off-system energy sales. Thus, the Net Fuel Cost portion of my estimated reduction in Ameren Missouri's ANEC will manifest itself through the year as a combination of increased off-system energy sales margins and decreased purchased energy costs.

Q ARE THE PRINCIPLES EXHIBITED IN THIS EXAMPLE FOR THE ENERGY MARKET GENERALLY APPLICABLE TO OTHER MISO MARKETS SUCH AS CAPACITY AND FOR THE WHOLESALE TRANSMISSION EXPENSES FOR THE NITS TAKEN BY AMEREN MISSOURI FROM MISO?

A Yes. With regard to capacity, the MISO conducts an annual capacity auction (the MISO Planning Resource Auction or "PRA"). Assuming a utility self-schedules all of its generation capacity into that auction, all of that utility's generation and load will clear in that auction at the capacity market clearing price. To the extent the utility has generation capacity in excess of its load requirements (including planning reserve margin and transmission losses), the loss of retail sales by that utility would increase its off-system capacity sales margins based on the capacity market clearing price. To the extent the utility has a deficit of generation capacity to meet its load requirements (including planning reserve margin and transmission losses), the loss of retail sales by that utility would decrease the utility's purchased capacity cost based on the capacity market clearing price.

With regard to Ameren Missouri's wholesale transmission expenses for the NITS it takes form MISO, the cost savings will be the lost retail sales applied to current MISO regional transmission rates. These savings will always appear in the utility's accounting as a reduction in the utility's wholesale transmission expenses.

Q WHAT ARE MISO SETTLEMENT CHARGES?

A MISO Settlement Charges is the term I am using to refer to Ameren Missouri's non-Asset Energy and non-capacity market settlement charges with MISO, Ameren Missouri's MISO market administration charges and Ameren Missouri's MISO transmission administration charges. The non-Asset Energy and non-capacity MISO market settlement charges are part of Ameren Missouri's ANEC. Ameren Missouri's load-sensitive MISO market administration and MISO transmission administration charges are part of Ameren Missouri's non-ANEC load-sensitive MISO charges. As detailed in Appendix B of my testimony, I estimated these avoided charges on the basis of Ameren Missouri's recent historical MISO settlement charges.

Q IS IT REASONABLE, AS YOU HAVE INDICATED, TO ASSUME THAT THE SHUTDOWN OF NORANDA'S NEW MADRID FACILITIES WOULD HAVE ONLY A SMALL DOWNWARD EFFECT ON MISO MARKET PRICES?

A Yes, in the context of how my estimate is being utilized in this proceeding it is reasonable. Specifically, the loss of Ameren Missouri's sales to Noranda due to a shutdown of Noranda's New Madrid facilities would remove the load associated with those sales from the Ameren Missouri load zone in the MISO market. To the extent such a reduction in demand has impact on market prices, it would be to lower the market prices in the Ameren Missouri load zone, the market prices at the generation nodes of Ameren Missouri's generation facilities and potentially market prices at other generation nodes and load zones within MISO.

Q YOU HAVE INDICATED THAT YOUR AVOIDED COST ESTIMATE THAT IS BASED ON THE SAME METHOD YOU USED IN YOUR SURREBUTTAL TESTIMONY IN CASE NO. EC-2014-0224 INCLUDED THE IMPACT OF THE SMALL REDUCTION IN ENERGY MARKET PRICES THAT WOULD RESULT FROM A SHUTDOWN OF NORANDA'S LOAD. PLEASE EXPLAIN HOW 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 I address this in Appendix C of my testimony.

IV. Conclusion

Q PLEASE SUMMARIZE YOUR CONCLUSIONS.

A For the reasons I discuss in detail in my testimony above, I conclude the following:

- All of Ameren Missouri's wholesale transmission expenses and revenues not associated with the transportation of fuel or purchased power should be removed from Ameren Missouri's FAC since Section 386.266.1, RSMo (Supp. 2011) only permits the inclusion of the cost of transportation for fuel and purchased power in a FAC – not the cost of transportation of power that is not purchased power. This will remove all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses from its FAC. This adjustment will not affect Ameren Missouri's base rate revenue requirement. However, it will increase the portion of that base rate revenue requirement included in Ameren Missouri's Net Base Energy Cost ("NBEC") by approximately $7.6 million[9] based on the test year wholesale transmission revenue and expense data Ameren Missouri included in its direct case. This NBEC adjustment will need to be recalculated during the true-up phase of this proceeding due to the significant drop in MISO point-to-point transmission expenses that Ameren Missouri has seen since the December 19, 2013 integration of Entergy into MISO.[10]

[9] $36.9 million in wholesale transmission revenues and 96.5% of $30.4 million in MISO wholesale transmission expenses would be removed from Ameren Missouri's NBEC.

[10] As an alternative to excluding all of Ameren Missouri's wholesale transmission revenues and 96.5% of its MISO wholesale transmission expenses, MIEC would be amenable to excluding all of Ameren Missouri's wholesale transmission revenues and expenses from its FAC. This alternative would exclude $36.9 million in wholesale transmission revenues and $32.3 million in wholesale transmission expenses from Ameren Missouri's NBEC, which would increase Ameren Missouri's NBEC by approximately $4.6 million rather than $7.6 million.

- The ANEC, and MISO load-based charges not included in Ameren Missouri's ANEC, that Ameren Missouri would avoid if Noranda's New Madrid facility was shut down ranges from $28.03 to $29.39 per MWh on a normalized historical basis using the same three year averaging approach with the Polar Vortex Anomaly normalized out that Ameren Missouri, Commission Staff and MIEC used in the revenue requirement part of the case to determine off-system sales prices. The number will vary some depending on the specific method used to estimate the annual reduction.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of James R. Dauphinais

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, USA.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation I was employed by the Transmission Planning Department of the Northeast Utilities Service Company as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast

Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000, Montana Power Company, Docket No. ER98-2382-000, Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003, SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000, Alliance Companies, et al., Docket No. EL02-65-000, et al., Entergy Services, Inc., Docket No.

ER01-2201-000, and Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000 and NorthWestern Corporation, Docket No. ER10-1138-001, et al. I have also filed or presented testimony before the Alberta Utilities Commission, Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group and Supply Adequacy Working Group. I am currently a member of the MISO Advisory Committee in the end-use customer sector on behalf of a group of industrial end-use customers in Illinois and a group of industrial end-use customers in Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Appendix B
<u>Estimate of Avoided MISO Settlement Charges</u>

Q PLEASE EXPLAIN HOW YOU HAVE CALCULATED MISO SETTLEMENT CHARGES ON THE BASIS OF AMEREN MISSOURI'S RECENT HISTORICAL MISO SETTLEMENT CHARGES.

A In response to Data Request MPSC 0010 in Case No. EC-2014-0224, 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 MISO market settlement charges applicable to Ameren Missouri for the past five years that are a function of Ameren Missouri's load. For each of these MISO market settlements items 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-7.

For ARR Day 2 Distribution Amounts, which were only used for my estimate of the reduction of ANEC and Non-ANEC load-sensitive MISO charges that is based on the method I used in my surrebuttal testimony in Case No. EC-2014-0224, 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-8.

In Schedules JRD-4 through JRD-6, 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 impact for MISO market settlement charges. This ranged from a net increase in charges of $0.18 per MWh to a net decrease in charges of $0.14 per MWh depending on whether the impact of the reduction in ARR revenues is included.

With respect to the MISO administration charges applicable to Ameren Missouri that are a function of Ameren Missouri's load, except for MISO Schedule 24, I used the April 2014 through March 2015 forecasted rate for each charge as posted by MISO on its website. For MISO Schedule 24, I used Ameren 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-7. Summing all of these MISO administration charges together in Schedules JRD-4 through JRD-6, 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.

Q ARE THERE ANY LOAD-BASED MISO WHOLESALE TRANSMISSION EXPENSES OR MISO SETTLEMENT CHARGES THAT NEEDED SPECIAL TREATMENT IN YOUR AVOIDED COST ESTIMATE?

A Yes. MISO Schedule 26 charges needed special treatment because of their unique nature whereby, while they are charged to Ameren Missouri on the basis of Ameren Missouri's load, the total charges Ameren Missouri experiences for MISO Schedule 26 are not necessarily materially affected by the amount of load Ameren Missouri serves. 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 change 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-9. 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 the avoided cost estimates that I present in Schedules JRD-3 through JRD-6.

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. in Case No. EC-2014-0224, Ameren Missouri identified a corrected annual Schedule 26 charge savings in the same neighborhood as the number I estimated above from publicly available data.

Appendix C
Estimated Impact of the Small Energy Market Price Reduction That Would Result From a Shutdown of Noranda Load

Q PLEASE EXPLAIN HOW 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 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 in my avoided cost estimate that is based on the method I used in my surrebuttal testimony in Case No. EC-2014-0224. 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[11] 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-10. 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).[12] 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.

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

[12]The average hourly load estimate was calculated from an older Noranda retail sales figure of 4,169,000 MWh rather than the more current figure of 4,198,453 MWh. The effect of not using the more current retail sales figure in this estimate was to slightly understate the estimated impact of the market price reduction that would result from a shutdown of the Noranda facility.

Q PLEASE EXPLAIN HOW YOU APPLIED THIS 1.5% ENERGY MARKET PRICE REDUCTION ESTIMATE TO YOUR ANEC IMPACT ESTIMATE BASED ON THE METHOD YOU USED IN YOUR CASE NO. EC-2014-0224 SURREBUTTAL TESTIMONY.

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 Schedule JRD-4 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 Noranda's load by $0.41 to $0.42 for every MWh that would have been sold to Noranda.

Second, in Schedule JRD-11, 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-11, 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 Schedule JRD-4, 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.

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Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258

MISO Forecast of MISO Schedule 26-A Multi-Value Project Charges as of July 31, 2014

Year	per MWh
2015	$ 0.58
2016	$ 0.80
2017	$ 1.15
2018	$ 1.36
2019	$ 1.60
2020	$ 1.63
2021	$ 1.65
2022	$ 1.62
2023	$ 1.59
2024	$ 1.56
2025	$ 1.53
2026	$ 1.50
2027	$ 1.47
2028	$ 1.44
2029	$ 1.41
2030	$ 1.38
2031	$ 1.36
2032	$ 1.33
2033	$ 1.30
2034	$ 1.28

Source: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177750

NON-PROPRIETARY

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

Annual Ameren Missouri Generation, Power Purchases, Off-System Sales and Load MWh
for Test Period as Presented in Ameren Missouri's Direct Case

Item	Million MWh
Generation	
Power Purchases	1.348
Total of Generation and Power Purchases	
Off-System Sales	
Load	38.763
Total of Off-System Sales and Load	

Source: Ameren Missouri Workpaper UE_DIR-UE_DIR_009-Att-Peters - 4-FBREPORT_UE_MPSC2014_May2014Run_PolarV.xlsx

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258

Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC")
and Non-ANEC MISO Load-Based Charges
Under a Noranda Shutdown

Description	36-Month Average with Polar Vortex Excluded		36-Month Average with Polar Vortex Excluded		48-Month Average with Polar Vortex Included	
	ARR Revenue and Market Price Reduction Impacts Included		ARR Revenue and Market Price Reduction Impacts Excluded		ARR Revenue and Market Price Reduction Impacts Excluded	
	Estimated Annual Reduction in Ameren Missouri ANEC and Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales	Estimated Annual Reduction in Ameren Missouri ANEC and Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales	Estimated Annual Reduction in Ameren Missouri ANEC and Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Core ANEC and Transmission Components	$ 119,726,965	$ 28.52	$ 121,460,127	$ 28.93	$ 131,324,182	$ 31.28
Additional ANEC MISO Market Settlement Components	$ (767,944)	$ (0.18)	$ 596,375	$ 0.14	$ 596,375	$ 0.14
Additional ANEC Off-System Energy Sales Revenue and Purchased Power Cost	$ (2,626,080)	$ (0.63)	$ -	$ -	$ -	$ -
Additional MISO Transmission Components	$ 55,370	$ 0.01	$ 55,370	$ 0.01	$ 55,370	$ 0.01
Subtotal of All Affected ANEC and Transmission Components	$ 116,388,310	$ 27.72	$ 122,111,872	$ 29.08	$ 131,975,927	$ 31.43
MISO Transmission Administration Charges	$ 882,958	$ 0.21	$ 882,958	$ 0.21	$ 882,958	$ 0.21
MISO Market Administration Charges	$ 398,219	$ 0.09	$ 398,219	$ 0.09	$ 398,219	$ 0.09
Subtotal of All Affected MISO Administration Charges	$ 1,281,177	$ 0.31	$ 1,281,177	$ 0.31	$ 1,281,177	$ 0.31
Total of All Affected ANEC Components and MISO Administration Charges	$ 117,669,487	$ 28.03	$ 123,393,048	$ 29.39	$ 133,257,104	$ 31.74

NON-PROPRIETARY

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and Non-ANEC MISO Load-Based Charges Under a Noranda Shutdown

36-Month Average with Polar Vortex Excluded and ARR Revenue and Market Price Reduction Impacts Included

(Ameren Missouri, Staff and MIEC NBEC Market Price Normalization Method with ARR Revenue and Market Price Reduction Impacts Included)

(Uses Average of Historic Energy Market Prices for December 2011 through November 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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ 26.59 per MWh			$ 115,544,156	$ 27.52
1.5% Market Price Reduction Impact on Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ (0.40) per MWh			$ (1,733,162)	$ (0.41)
Net Capacity Costs	202,602 MW-days	$ 16.75 per MW-day			$ 3,393,577	$ 0.81
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,345,399 MWh		$ 0.58 per MWh		$ 2,522,394	$ 0.60
Core ANEC and Transmission Components					**$ 119,726,965**	**$ 28.52**
MISO Day-Ahead RSG Distribution Amount	4,345,399 MWh	per MWh				
MISO Real-Time Distribution of Losses Amount	4,345,399 MWh	per MWh				
MISO Real-Time Miscellaneous Amount	4,345,399 MWh	per MWh				
MISO Real-Time Net Inadvertent Amount	4,345,399 MWh	per MWh				
MISO Real-Time Revenue Neutrality Uplift Amount	4,345,399 MWh	per MWh				
MISO Real-Time RSG First Pass Distribution Amount	4,345,399 MWh	per MWh				
MISO Regulation Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Spinning Reserve Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Supplemental Reserve Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Auction Revenue Rights (ARR) Stage 2 Distribution Amount (see Schedule JRD-8)	506.17 MW-years	per MW-year				
Additional ANEC MISO Market Settlement Components					**$ (767,944)**	**$ (0.18)**
1.5% Market Price Reduction Impact on other OSS Revenues and PP Costs (see Schedule JRD-11)	N/A				$ (2,626,080)	$ (0.63)
Additional 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-9)	N/A				$ 55,370	$ 0.01
Additional MISO Transmission Components					**$ 55,370**	**$ 0.01**
Subtotal of All Affected ANEC and Transmission Components					**$ 116,388,310**	**$ 27.72**

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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
MISO Tariff Schedule 10 Administration Charge (Energy Rate Portion)	4,345,399	MWh		$ 0.09	per MWh		$ 384,669	$ 0.09
MISO Tariff Schedule 10 Administration Charge (Demand Rate Portion)	4,531,630	MWh		$ 0.07	per MWh		$ 295,372	$ 0.07
MISO Tariff Schedule 10-FERC Charge (MISO FERC Assessment)	4,531,630	MWh		$ 0.04	per MWh		$ 202,917	$ 0.05
MISO Transmission Administration Charges							**$ 882,958**	**$ 0.21**
MISO Day-Ahead Market Administration (MISO Schedule 17)	4,345,399	MWh		$ 0.07	per MWh		$ 325,340	$ 0.08
MISO Day-Ahead Schedule 24 Allocation Amount	4,345,399	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							**$ 398,219**	**$ 0.09**
Subtotal of All Affected MISO Administration Charges							**$ 1,281,177**	**$ 0.31**
Total of All Affected ANEC Components and MISO Administration Charges							**$ 117,669,487**	**$ 28.03**

Sources:

The $26.59 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 November 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. This is essentially the same market price normalization method as that proposed by Ameren Missouri, Staff and MIEC for the determination of Ameren Missouri's Net Base Energy Cost ("NBEC") for its Fuel Adjustment Clause.

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 $0.58 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2015 as of July 31, 2014 as posted on the MISO website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177750.

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 4,198,453 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor at Noranda's meter. These sales gross up to 4,345,399 MWh at the AECI/MISO border due to AECI's 3.5% loss factor under Noranda transmission service agreement with AECI.

202,602 MW-days = 4,345,399 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 per

517.31 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 102.2% (MISO Transmission Losses)

4,531,630 MWh = 517.31 MW-years x 8,760 hours per year

506.17 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor)

NON-PROPRIETARY

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and Non-ANEC MISO Load-Based Charges Under a Noranda Shutdown

36-Month Average with Polar Vortex Excluded and ARR Revenue and Market Price Reduction Impacts Excluded

(Ameren Missouri, Staff and MIEC NBEC Market Price Normalization Method with ARR Revenue and Market Price Reduction Impacts Excluded)

(Uses Average of Historic Energy Market Prices for December 2011 through November 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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ 26.59 per MWh		$ 115,544,156	$ 27.52
1.5% Market Price Reduction Impact on Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ - per MWh		$ -	$ -
Net Capacity Costs	202,602 MW-days	$ 16.75 per MW-day		$ 3,393,577	$ 0.81
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,345,399 MWh		$ 0.58 per MWh	$ 2,522,394	$ 0.60
Core ANEC and Transmission Components				**$ 121,460,127**	**$ 28.93**
MISO Day-Ahead RSG Distribution Amount	4,345,399 MWh	per MWh			
MISO Real-Time Distribution of Losses Amount	4,345,399 MWh	per MWh			
MISO Real-Time Miscellaneous Amount	4,345,399 MWh	per MWh			
MISO Real-Time Net Inadvertent Amount	4,345,399 MWh	per MWh			
MISO Real-Time Revenue Neutrality Uplift Amount	4,345,399 MWh	per MWh			
MISO Real-Time RSG First Pass Distribution Amount	4,345,399 MWh	per MWh			
MISO Regulation Cost Distribution Amount	4,345,399 MWh	per MWh			
MISO Spinning Reserve Cost Distribution Amount	4,345,399 MWh	per MWh			
MISO Supplemental Reserve Cost Distribution Amount	4,345,399 MWh	per MWh			
MISO Auction Revenue Rights (ARR) Stage 2 Distribution Amount (see Schedule JRD-8)	506.17 MW-years	per MW-year			
Additional ANEC MISO Market Settlement Components				**$ 596,375**	**$ 0.14**
1.5% Market Price Reduction Impact on other OSS Revenues and PP Costs (see Schedule JRD-11)	N/A			$ -	$ -
Additional ANEC Off-System Energy Sales Revenue and Purchased Power Cost Components				**$ -**	**$ -**
MISO Tariff Schedule 26 Network Upgrade Charge (see Schedule JRD-9)	N/A			$ 55,370	$ 0.01
Additional MISO Transmission Components				**$ 55,370**	**$ 0.01**
Subtotal of All Affected ANEC and Transmission Components				**$ 122,111,872**	**$ 29.08**

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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
MISO Tariff Schedule 10 Administration Charge (Energy Rate Portion)	4,345,399 MWh		$ 0.09 per MWh		$ 384,669	$ 0.09
MISO Tariff Schedule 10 Administration Charge (Demand Rate Portion)	4,531,630 MWh		$ 0.07 per MWh		$ 295,372	$ 0.07
MISO Tariff Schedule 10-FERC Charge (MISO FERC Assessment)	4,531,630 MWh		$ 0.04 per MWh		$ 202,917	$ 0.05
MISO Transmission Administration Charges					**$ 882,958**	**$ 0.21**
MISO Day-Ahead Market Administration (MISO Schedule 17)	4,345,399 MWh		$ 0.07 per MWh		$ 325,340	$ 0.08
MISO Day-Ahead Schedule 24 Allocation Amount	4,345,399 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					**$ 398,219**	**$ 0.09**
Subtotal of All Affected MISO Administration Charges					**$ 1,281,177**	**$ 0.31**
Total of All Affected ANEC Components and MISO Administration Charges					**$ 123,393,048**	**$ 29.39**

Sources:

The $26.59 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 November 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. This is essentially the same market price normalization method as that proposed by Ameren Missouri, Staff and MIEC for the determination of Ameren Missouri's Net Base Energy Cost ("NBEC") for its Fuel Adjustment Clause.

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 $0.58 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2015 as of July 31, 2014 as posted on the MISO website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177750.

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 4,198,453 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor at Noranda's meter. These sales gross up to 4,345,399 MWh at the AECI/MISO border due to AECI's 3.5% loss factor under Noranda transmission service agreement with AECI.

202,602 MW-days = 4,345,399 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 per

517.31 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 102.2% (MISO Transmission Losses)

4,531,630 MWh = 517.31 MW-years x 8,760 hours per year

506.17 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor)

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC") and Non-ANEC MISO Load-Based Charges Under a Noranda Shutdown

48-Month Average with Polar Vortex Excluded and ARR Revenue and Market Price Reduction Impacts Excluded

(Case No. EC-2014-0224 Market Price Normalization Method of Staff Witness Kliethermes with ARR Revenue and Market Price Reduction Impacts Excluded)

(Uses Average of Historic Energy Market Prices for December 2010 through November 2014 with January through March of 2014 Included)

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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ 28.86 per MWh			$ 125,408,211	$ 29.87
1.5% Market Price Reduction Impact on Net Energy, Transmission Loss and Congestion Costs	4,345,399 MWh	$ - per MWh			$ -	$ -
Net Capacity Costs	202,602 MW-days	$ 16.75 per MW-day			$ 3,393,577	$ 0.81
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,345,399 MWh		$ 0.58 per MWh		$ 2,522,394	$ 0.60
Core ANEC and Transmission Components					**$ 131,324,182**	**$ 31.28**
MISO Day-Ahead RSG Distribution Amount	4,345,399 MWh	per MWh				
MISO Real-Time Distribution of Losses Amount	4,345,399 MWh	per MWh				
MISO Real-Time Miscellaneous Amount	4,345,399 MWh	per MWh				
MISO Real-Time Net Inadvertent Amount	4,345,399 MWh	per MWh				
MISO Real-Time Revenue Neutrality Uplift Amount	4,345,399 MWh	per MWh				
MISO Real-Time RSG First Pass Distribution Amount	4,345,399 MWh	per MWh				
MISO Regulation Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Spinning Reserve Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Supplemental Reserve Cost Distribution Amount	4,345,399 MWh	per MWh				
MISO Auction Revenue Rights (ARR) Stage 2 Distribution Amount (see Schedule JRD-8)	506.17 MW-years	per MW-year				
Additional ANEC MISO Market Settlement Components					**$ 596,375**	**$ 0.14**
1.5% Market Price Reduction Impact on other OSS Revenues and PP Costs (see Schedule JRD-11)	N/A				$ -	$ -
Additional ANEC Off-System Energy Sales Revenue and Purchased Power Cost Components					**$ -**	**$ -**
MISO Tariff Schedule 26 Network Upgrade Charge (see Schedule JRD-9)	N/A				$ 55,370	$ 0.01
Additional MISO Transmission Components					**$ 55,370**	**$ 0.01**
Subtotal of All Affected ANEC and Transmission Components					**$ 131,975,927**	**$ 31.43**

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 Non-ANEC MISO Load-Based Charges	Estimated Annual Reduction in Ameren Missouri Costs per MWh of Noranda Retail Sales
MISO Tariff Schedule 10 Administration Charge (Energy Rate Portion)	4,345,399 MWh		$ 0.09 per MWh	$ 384,669	$ 0.09
MISO Tariff Schedule 10 Administration Charge (Demand Rate Portion)	4,531,630 MWh		$ 0.07 per MWh	$ 295,372	$ 0.07
MISO Tariff Schedule 10-FERC Charge (MISO FERC Assessment)	4,531,630 MWh		$ 0.04 per MWh	$ 202,917	$ 0.05
MISO Transmission Administration Charges				**$ 882,958**	**$ 0.21**
MISO Day-Ahead Market Administration (MISO Schedule 17)	4,345,399 MWh		$ 0.07 per MWh	$ 325,340	$ 0.08
MISO Day-Ahead Schedule 24 Allocation Amount	4,345,399 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				**$ 398,219**	**$ 0.09**
Subtotal of All Affected MISO Administration Charges				**$ 1,281,177**	**$ 0.31**
Total of All Affected ANEC Components and MISO Administration Charges				**$ 133,257,104**	**$ 31.74**

Sources:

The $28.86 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 48 months ending November 30, 2014 (with January through March of 2014 included) as posted on the MISO website. This is essentially the same market price normalization method as that proposed by Staff witness Sarah Kliethermes in Case No. EC-2014-0224. This method deviates from that proposed by Ameren Missouri, Staff and MIEC in this current proceeding for setting Ameren Missouri's Net Base Energy Cost ("NBEC") for its Fuel Adjustment Clause.

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 $0.58 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2015 as of July 31, 2014 as posted on the MISO website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=177750.

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 4,198,453 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor at Noranda's meter. These sales gross up to 4,345,399 MWh at the AECI/MISO border due to AECI's 3.5% loss factor under Noranda transmission service agreement with AECI.

202,602 MW-days = 4,345,399 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 per

517.31 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 102.2% (MISO Transmission Losses)

4,531,630 MWh = 517.31 MW-years x 8,760 hours per year

506.17 MW-years = 4,345,399 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor)

NON-PROPRIETARY

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

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 EC-2014-0224 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 EC-2014-0224 Data Request MPSC 0010

NON-PROPRIETARY

Ameren Missouri
Missouri Public Service Commission Case No. ER-2014-0258 = HC

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 EC-2014-0224 Data Request Noranda 4-27 i.

Total 2013 ARR Stage 2 Distribution Amount Settlement (Ameren Missouri Response to EC-2014-0224 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. ER-2014-0258

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	4,198,453,000	kWh	Assumed to be 4,198,453 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	517,056	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	6,330,841	kW	Line 2 - Line 7
9	**Noranda Shutdown MISO Schedule 26 Rate for MISO Transmission Pricing Zone 3B**	**$ 0.1548**	**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**	**71,232,324**	**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)**	**$ 11,025,518**		Line 24 x Line 9
27	**Estimated Annual Ameren Missouri MISO Schedule 26 Charge Savings from Noranda Shutdown**	**$ 55,370**		Line 25 - Line 26

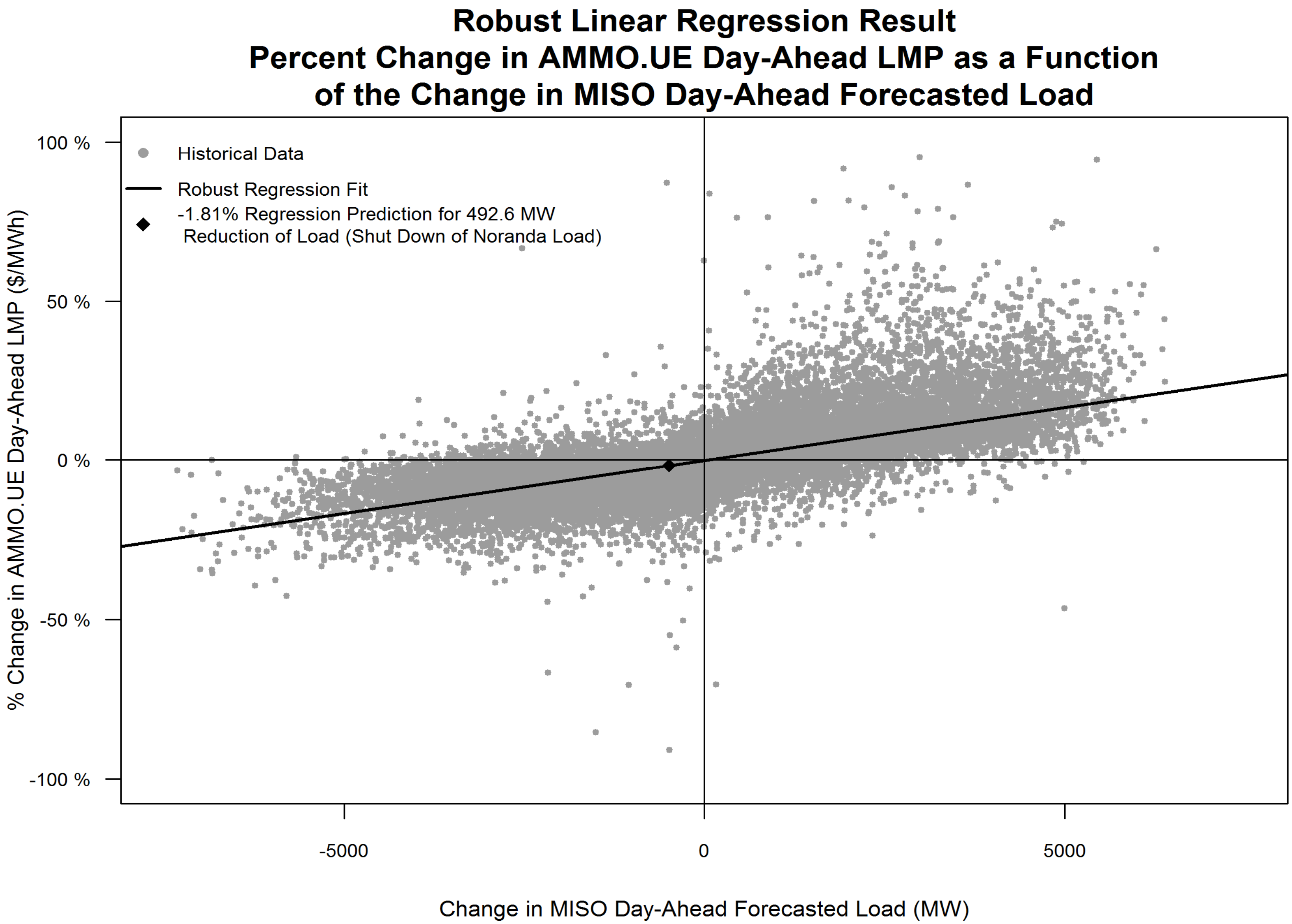
Statistical Analysis of Historical Hourly Market Energy Price Changes as a Function of Hourly Load Changes

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)



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	[redacted]	[redacted]	[redacted]	Ameren Missouri Monthly FAC Reports Jan 2012 thru Dec 2012, Page - 5C p1
3	2013 Subtotal	[redacted]	[redacted]	[redacted]	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-10, 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