Exhibit No.:	
Issue:	Revenue Requirement
Witness:	Nicholas L. Phillips
Type of Exhibit:	Direct Testimony
Sponsoring Party:	MIEC
Case No.:	ER-2014-0258
Date Testimony Prepared:	December 5, 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

Nicholas L. Phillips

On behalf of

Missouri Industrial Energy Consumers

December 5, 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 Nicholas L. Phillips

Nicholas L. Phillips, being first duly sworn, on his oath states:

1. My name is Nicholas L. Phillips. 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.

Nicholas L Phillips
Nicholas L. Phillips

Subscribed and sworn to before me this 4th 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

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**

Table of Contents to the
<u>Direct Testimony of Nicholas L. Phillips</u>

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 of Nicholas L. Phillips

I. Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas L. Phillips. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Senior Consultant in the field of public utility regulation and an Associate 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"). 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 testified in Case Nos. ER-2012-0166, ER-2012-0174, and ER-2012-0175 before the Commission regarding fuel cost, purchase power expense, and off-system sales revenue.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A My testimony addresses the Net Base Energy Cost ("NBEC") that Ameren Missouri proposes to include in its revenue requirement. Specifically, I address the Other Fuel and Purchased Power Costs and Other Sales Revenues components of Ameren Missouri's NBEC. My colleague, Mr. Brian Andrews, addresses issues related to the Net Fuel Cost component of Ameren Missouri's NBEC.

The fact that I do not address a particular issue should not be interpreted as approval of any position taken by Ameren Missouri.

Q PLEASE EXPLAIN THE DIFFERENCE BETWEEN NBEC AND NET BASE FUEL COST.

A In previous proceedings, Ameren Missouri used the term Net Base Fuel Costs to describe the portion of its revenue requirement that is tracked through the Fuel Clause. During the last rate proceeding, ER-2012-0166, the Company changed its terminology, replacing Net Base Fuel Costs with NBEC.

Q IN PAST PROCEEDINGS, YOU HAVE TESTIFIED ON BEHALF OF MIEC CONCERNING AMEREN MISSOURI'S NET FUEL COST ISSUES. HAVE YOU REVIEWED MR. ANDREWS' DIRECT TESTIMONY AND ANALYSIS IN THIS PROCEEDING WITH REGARD TO THOSE ISSUES?

A Yes. I have carefully reviewed Mr. Andrews' direct testimony and the analysis that underlies that direct testimony. I concur with the results of his analysis and his recommendations to the Commission with regard to the Net Fuel Cost component of Ameren Missouri's NBEC.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission reduce Ameren Missouri's proposed NBEC from its original filing in this case (and, thus, its original filing revenue requirement) by at least $24.0 million. This $24 million addresses: (i) the $6.35 million adjustment of Net Fuel Cost identified in Mr. Andrews' direct testimony; (ii) the $8.85 million adjustment to Other Fuel and Purchased Power Costs that I have identified herein; and (iii) the $8.8 million adjustment to Other Sales Revenues that I have identified herein.

II. NBEC

Q PLEASE EXPLAIN THE TERM NBEC.

A Ameren Missouri's NBEC is the portion of Ameren Missouri's revenue requirement that is tracked through its Fuel Adjustment Clause. The NBEC established in this proceeding will set the base level of energy expense Ameren Missouri is authorized to collect through base rates. The FAC tracks and reconciles prudently incurred deviations in actual net energy cost above or below this established base level. The NBEC consists of three major components:

1. **Net Fuel Cost** – Fuel and purchased power costs for native load and off-system sales, less revenues from off-system sales of energy, as estimated using production cost modeling.

   Plus

2. **Other Fuel and Purchased Power Costs** – Fuel additive costs, net fly ash revenues and expenses, fixed gas supply costs, credits from Westinghouse related to a prior nuclear fuel settlement, MISO Day 2 expenses, PJM expenses, Account 565 transmission expenses, MISO ancillary service costs, and the cost of purchased power to serve common boundary customers.

   Less

3. **Other Sales Revenues** – Off-system sales of capacity, MISO ancillary service revenues and MISO Day 2 revenues (including MISO RSG Make Whole Payment Margins).[1]

   (Direct Testimony of Moore at 29-30, Direct Testimony of Peters at 2-3 and Direct Testimony of Haro at 3-5).

Q **WHAT STANDARD SHOULD THE COMMISSION USE TO SET THE NBEC COMPONENT OF AMEREN MISSOURI'S REVENUE REQUIREMENT?**

A It should be set on the same standard as the remainder of Ameren Missouri's revenue requirement. Specifically, it should be set based on Ameren Missouri's actual costs during the historic test year ending March 31, 2014 adjusted for known and measurable changes from the true-up period that ends December 31, 2014, annualized for periodic expenses and normalized to address abnormalities such as annual swings in weather and commodity market prices.

[1]As will be discussed later in this testimony, this component of NBEC should also include net Load and Generation Forecasting Deviation costs, Ameren Missouri's net Bilateral Off-System Energy Sales Margins and net Swap Margins since they are not included in Ameren Missouri's estimate of Net Fuel Cost.

Q WHAT IS THE TOTAL ANNUAL NBEC THAT AMEREN MISSOURI PROPOSED IN ITS ORIGINAL FILING IN THIS PROCEEDING?

A Ameren Missouri proposed a NBEC of approximately $696.2 million. This consists of a Net Fuel Cost of $673.7 million plus Other Fuel and Purchased Power Costs of $42.4 million less Other Sales Revenues of approximately $19.9 million (Schedule LMM-17, Direct Testimony of Peters at 2-3 and Direct Testimony of Haro at 5). The amount is an approximately $127 million increase from the NBEC approved by the Commission for Ameren Missouri in Case No. ER-2012-0166.

Q PLEASE DESCRIBE YOUR REVIEW OF AMEREN MISSOURI'S PROPOSED NBEC AMOUNT.

A I reviewed the Direct Testimony and Schedules of Ameren Missouri witnesses Mark Peters, Jaime Haro and Laura Moore concerning NBEC. I also reviewed Ameren Missouri's response to data requests in this proceeding that relate to the issue. In addition, I reviewed Mr. Andrews' analysis and direct testimony related to the Net Fuel Cost component of Ameren Missouri's NBEC. Finally, I applied my experience to the information available in considering the reasonableness of Ameren Missouri's proposed NBEC amount. As I have noted, I have identified issues with Ameren Missouri's proposed level of Other Fuel and Purchased Power Costs and Other Sales Revenues. In addition, Mr. Andrews has identified issues related to certain assumptions Ameren Missouri used in its production cost modeling for Net Fuel Cost.

A. Adjustments to Net Fuel Cost

Q PLEASE SUMMARIZE THE RECOMMENDED ADJUSTMENTS TO THE NET FUEL COST COMPONENT OF AMEREN MISSOURI'S NBEC.

A We are recommending a $6.35 million reduction to Ameren Missouri's Net Fuel Cost from Ameren Missouri's original filed Net Fuel Cost value. As Mr. Andrews discusses in detail in his direct testimony, the reduction includes an update to the commodity price assumptions used by Ameren Missouri, as well as a normalization adjustment to remove the effects of the Polar Vortex from natural gas price assumptions input into the production cost model. Later in my testimony, I discuss the Polar Vortex in further detail.

Q SHOULD THIS VALUE BE UPDATED ONCE DATA THROUGH THE END OF THE TRUE-UP PERIOD BECOMES AVAILABLE?

A Yes, the production cost modeling should be further updated at that time.

B. The Polar Vortex

Q PLEASE DESCRIBE THE POLAR VORTEX.

A The Polar Vortex is a term commonly used to refer to the period of severe weather experienced between January 1, 2014 and March 31, 2014.[2] During this period, the Midwest, Mid-Atlantic, South Central and Southeast United States experienced the coldest temperatures seen in many years. These extremely low temperatures led to very high natural gas and electricity demand, as well as non-firm natural gas disruptions, coal pile freeze ups and other forced generation derates and outages.[3]

[2] Direct Testimony of Jamie Haro at Page 8.

[3] Forced generation derates refers to unplanned periods when a generating unit is limited to some output level less than the unit's maximum capability.

All of this elevated hourly day-ahead and Real-Time electricity market prices to astronomical levels not experienced in the Midwest since the late 1990s. My colleague, James Dauphinais, provided a very detailed discussion of the Polar Vortex and its effects on electricity and natural gas prices throughout MISO, PJM, SPP, and the Northeast in his surrebettual testimony in Case No. EC-2014-0224.

Q HAS THE COMPANY ADJUSTED ANY OF ITS ASSUMPTIONS USED TO CALCULATE ITS PROPOSED NBEC TO ACCOUNT FOR THE POLAR VORTEX?

A Yes. Mr. Haro briefly discussed that the market price assumptions that were used to model the dispatch of Ameren Missouri's generation were adjusted to account for this severe weather anomaly, commonly referred to as the "Polar Vortex."[4] The adjustment removed the market prices that actually occurred during the Polar Vortex, replaced them with the average prices for the applicable peak period by month, from January 2012 – March 2012, and is consistent with the Company's previous treatment of other severe weather anomalies.[5]

Q DO YOU AGREE WITH MR. HARO'S DESCRIPTION REGARDING THE METHOD USED TO ADJUST ELECTRIC MARKET PRICES TO ACCOUNT FOR THE POLAR VORTEX?

A No. After reviewing Mr. Peters' workpapers, the adjustment Mr. Haro made to the electric market prices actually replaced the prices from the three-month Polar Vortex period with the average prices of the applicable peak period by month for January 2012 – March 2012 and January 2013 – March 2013 (not just January 2012 – March 2012 as Mr. Haro indicated in his testimony).

[4]Direct Testimony of Jamie Haro at Page 8.
[5]Direct Testimony of Jaime Haro at Pages 7-8.

Q HAS THE COMPANY ADJUSTED ANY OTHER ASSUMPTIONS USED TO CALCULATE ITS PROPOSED NBEC TO ACCOUNT FOR THE POLAR VORTEX?

A No.

Q WERE WHOLESALE MARKET ELECTRIC ENERGY PRICES THE ONLY COSTS HIGHLY SENSITIVE TO THE POLAR VORTEX?

A No. Natural gas spot and futures prices, as well as MISO Market Settlement Charge Types, are also highly sensitive to the effects of the Polar Vortex and should be treated in a manner similar to the electric market prices adjusted by Mr. Haro. We propose similar adjustments for these costs, which are necessary in order to establish a normal level of energy expense.

Ameren Missouri's adjustment to the electric market prices assumed in its production cost model lowers its expected off-system sales revenues. Essentially, the Company's position is that the effects of the Polar Vortex were so severe, that the inclusion of these prices, even when using a 36-month average for electric market prices, would skew the market prices assumptions and bias the results of the production cost simulations by overestimating off-system sales revenues. What Ameren Missouri has failed to recognize is that the severe distortions in the market were not limited to solely electric energy prices, but also to natural gas markets, as well as MISO Market Settlement Charge Types.

C. *Adjustments to Other Fuel and Purchased Power Costs*

Q HAVE YOU UPDATED ANY OF AMEREN MISSOURI'S ORIGINAL FILED VALUES FOR THE OTHER FUEL AND PURCHASED POWER COSTS COMPONENT OF NBEC?

A Yes. I have calculated two adjustments to Ameren Missouri's original filed values for the Other Fuel and Purchased Power Costs component of the NBEC. First, I have removed the effects of the Polar Vortex from Ameren Missouri's MISO Day 2 Account 555 Market Charges and the Ancillary Service Account 555 Market Charges and annualized the remaining nine months of test year charges to estimate a Polar Vortex adjusted amount of expenses to include in base rates. My second adjustment is to add a line item for net Load and Generation Forecasting Deviation error expense.

Q PLEASE EXPLAIN HOW YOU REMOVED THE EFFECTS OF THE POLAR VORTEX FROM THE MISO MARKET SETTLEMENT CHARGE TYPES INCORPORATED INTO ACCOUNT 555 EXPENSES INCLUDED IN THE NBEC.

A Ms. Moore's workpaper supporting the NBEC calculation ("UE_DIR-UE_DIR_004-Att-Ameren Missouri NBEC.xlsx") includes the 12 months (April 2013 – March 2014) of MISO expenses and revenues incorporated into the NBEC. I propose removing the expenses and revenues incurred during Polar Vortex period from the data. I then arrive at my adjusted levels by arithmetically averaging the remaining nine months of data and annualizing the result by multiplying by a factor of twelve-ninths, as presented in Schedule NLP-1. The result of this calculation is a net reduction in other fuel and purchase power expense of approximately $6.1 million.

Q PLEASE EXPLAIN THE TERM NET LOAD AND GENERATION FORECASTING DEVIATION ERROR.

A The net Load and Generation Forecasting Deviation error refers to the additional costs and revenues associated with actual market settlements as compared to what such settlements would have been had Ameren Missouri's day-ahead awards perfectly matched their actual Real-Time load and generation levels. Ameren Missouri's load is bid into the market on a day-ahead basis using a load forecast representing its best estimate of what its load obligation will be in each hour of the next market day. It also seeks to have its generating assets clear on a day-ahead basis. At the end of each day, the MISO issues day-ahead awards for each generating asset, as well as the load. Deviations from these day-ahead awards result in additional costs or revenues, as compared to what the Company would have received if its day-ahead awards perfectly matched its actual load and generation levels in Real-Time. These additional costs/revenues can be measured by multiplying the deviation from the day-ahead award by the difference in price between the Real-Time MISO market Locational Marginal Price ("LMP") and the day-ahead LMP. This calculation is done for each hour, for the load and each generation asset with the exception of the Company's combustion turbine generating units ("CTGs"). The CTGs are excluded due to the high number of reliability starts required by the MISO, which occur separately from the economic dispatch process and the associated Revenue Sufficiency Guarantee make-whole payments.

For generating assets, additional benefits are achieved when (1) the Real-Time LMP is higher than the day-ahead LMP and the Real-Time output level is higher than the day-ahead award or (2) when the Real-Time LMP is lower than the day-ahead LMP and the Real-Time output level is lower than the day-ahead award.

Additional costs are incurred however if the change in LMP is in the opposite direction of the change in the Real-Time output level. For the load, it is the opposite. Additional benefits are achieved when (1) the Real-Time LMP is higher than the day-ahead LMP and the Real-Time metered load is lower than the day-ahead award or (2) when the Real-Time LMP is lower than the day-ahead LMP and the Real-Time metered load is higher than the day-ahead award. Additional costs are incurred when the deviation in LMP is in the same direction as the deviation in load.[6]

Q HAS AMEREN MISSOURI INCLUDED AN ESTIMATE OF A NET LOAD AND GENERATION FORECASTING DEVIATION CHARGES IN ITS NBEC AS FILED?

A It is unclear. No specific line item exists for net Load and Generation Forecasting Deviation in Schedule LMM-17; however, the supporting workpaper indicates Company witness Mark Peters provided an estimate of $0. In MIEC's Data Request 15.1 to Ameren Missouri, I asked that the Company provide a workpaper, similar to Mr. Peters' workpaper used in Case No. ER-2012-0166 to support the net Load and Generation Forecasting Deviation error estimates. The Company responded to MIEC's Data Request 15.1 stating that no such calculation has been performed in this case. I have also prepared my own estimate of net Load and Generation Forecasting Deviation error expense.

[6]Direct Testimony of Mark Peters, Case No ER-2012-0166 at Pages 10-11.

Q PLEASE DESCRIBE HOW YOU ESTIMATED A NORMAL LEVEL OF NET LOAD AND GENERATION FORECASTING DEVIATION EXPENSE TO INCLUDE IN THE NBEC.

A We reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) E data ("3.190 Data") submittals, which were provided to MIEC for November 2011 through October 2014 through a combination of data request responses and non-unanimous stipulations in Case Nos. ER-2010-0036 and ER-2011-0028. Included in this data are Real-Time Generation Deviations for each of Ameren Missouri's generators on an hourly basis, as well as Ameren Missouri's Real-Time hourly load deviations. I extracted the generation deviations for each of Ameren Missouri's non-CTG generating units for the 36-month period from November 1, 2011 through October 31, 2014. I then calculated the monthly generation deviation revenue for each month in the 36 month period by multiplying the Real-Time Generation Deviation by the difference between the Real-Time and Day-Ahead LMPs for the appropriate generator node. I performed a similar calculation for Ameren Missouri's load deviation costs. I then normalized the costs and revenues by removing the three Polar Vortex months and annualized the remainder of the data, consistent with the Company's treatment of electric market prices.[7] The net result is $2.75 million in additional revenue, which needs to be reflected in the NBEC, is presented in Schedule NLP-2.

[7]Consistent with our understanding of how the Company adjusted electric market prices to account for the Polar Vortex, the 3 months of data from January 2014-March 2014 have been replaced with an average of the data from January 2012-March 2012 and January 2013-March 2013.

Q SHOULD AMEREN MISSOURI'S OTHER FUEL AND PURCHASED POWER COSTS VALUE BE FURTHER UPDATED ONCE DATA THROUGH THE END OF THE TRUE-UP PERIOD IS OBSERVED?

A Yes. All of the values that make up Ameren Missouri's Other Fuel and Purchased Power Costs should be updated through the end of December 31, 2014 once the necessary historical data becomes available.

Q ARE YOU PROPOSING ANY OTHER ADJUSTMENTS AT THIS TIME TO AMEREN MISSOURI'S ORIGINAL FILED VALUES FOR THE OTHER FUEL AND PURCHASED POWER COSTS COMPONENT OF NBEC?

A No. While I continue my review of Ameren Missouri's filing and will review the direct testimony of other parties in this proceeding with regard to this issue, I am not currently proposing any other adjustments to Ameren Missouri's proposed Other Fuel and Purchased Power Costs.

Q CAN YOU PLEASE SUMMARIZE ALL OF YOUR PROPOSED ADJUSTMENTS AT THIS TIME TO AMEREN MISSOURI'S PROPOSED LEVEL OF OTHER FUEL AND PURCHASED POWER EXPENSES?

A Yes. My total adjustment at this time is a net $8.85 million decrease to Ameren Missouri's proposed level of Other Fuel and Purchase Power Expense, which would result in a reduction of the same amount to Ameren Missouri's NBEC and Revenue Requirement. The $8.85 million net decrease of Other Fuel and Purchase Power Expense consists of a $6.1 million decrease in expense due to updated MISO market settlement expense values and the inclusion of $2.75 million in net Load and Generation Forecasting Deviation error revenues.

D. Adjustments to Other Sales Revenues

Q HAVE YOU UPDATED ANY OF AMEREN MISSOURI'S ORIGINAL FILED VALUES FOR THE OTHER SALES REVENUES COMPONENT OF NBEC?

A Yes. I have calculated three adjustments to Ameren Missouri's original filed values for the Other Sales Revenues component of the NBEC. First, I have added approximately $2.49 million of RSG MWP Margin back into the NBEC that was originally removed by the Company.[8] My second adjustment is to remove the effects of the Polar Vortex from Ameren Missouri's MISO Day 2 Revenues - RSG MWP Margins, MISO Day 2 Revenues - Inadvertent Distribution and Ancillary Service Revenues in Account 447. My third adjustment is to add line items for Bilateral Off-System Energy Sales Margins and Financial Swap Margins.

Q PLEASE DEFINE AND EXPLAIN THE RELEVANCE OF MISO RSG MWP MARGINS.

A MISO RSG MWP Margins are the make whole payment revenues that Ameren Missouri receives under the Midwest Independent Transmission System Operator, Inc.'s ("MISO") RSG provisions less the additional fuel cost Ameren Missouri incurs due to MISO's commitment of Ameren Missouri's generation facilities that is not captured in the normalized test year production cost simulation Ameren Missouri performs to estimate its Net Fuel Cost.

Under MISO's RSG provisions, MISO guarantees that any generator it commits online will earn revenue at least equal to the sum of the startup, no load and energy offer prices of that generator. When the LMP paid by MISO to a generator for energy produced pursuant to MISO's dispatch orders is insufficient to cover the sum

[8]Workpaper "UE_DIR-UE_DIR_004-Att-Ameren Missouri NBEC.xlsx".

of startup, no load and energy offer prices for that generator, the MISO will pay a make whole payment to the generator to cover those offer prices. This typically happens when MISO orders a generator (e.g., a combustion turbine generator) online out-of-merit order for reliability purposes.[9]

Neither the RSG MWP Ameren Missouri receives nor the out-of-merit order energy production required of Ameren Missouri's generation facilities by MISO is reflected in the normalized test year production cost model run that Ameren Missouri uses to estimate its Net Fuel Cost. As a result, the difference between the RSG MWP Ameren Missouri receives from MISO and the out-of-merit order fuel cost Ameren Missouri incurs due to MISO must be included separately in the Other Sales Revenues component of Ameren Missouri's NBEC.

Q HAS AMEREN MISSOURI IDENTIFIED THE AMOUNT OF MISO RSG MWP IT RECEIVED DURING THE TEST PERIOD IN THIS PROCEEDING?

A Yes. Ms. Moore's workpapers identify approximately $5.9 million of MISO RSG MWP during the test year for this proceeding. This $5.9 million is the result of netting $4.9 million in Price Volatility and Net Regulation Adjustment from $10.8 million in Total RSG and Deviation Revenues.

Q IS THIS CONSISTENT WITH THE WAY THE COMPANY CALCULATED RSG MWP MARGINS IN PREVIOUS CASES?

A No, this is a departure from the way the Company has calculated the RSG MWP Margins in previous cases. In previous cases, the Company has multiplied the full

[9]Economic merit order refers to the dispatch the next lowest cost resource.

level of Total RSG and Deviation Revenues by a MWP Margin percentage to arrive at the estimated level to include in the NBEC.

Q HAS AMEREN MISSOURI PROVIDED TESTIMONY SUPPORTING THE CHANGE IN METHODOLOGY IN CALCULATING RSG MWP MARGINS?

A No. Based on informal discussions with the Company, we generally understand why the Company is making the adjustment. However, the Company has not demonstrated that its methodology for determining the MWP Margin Percentage is still appropriate given its change to the method for determining RSG MWP Revenues.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE MISO RSG MWP MARGINS ISSUE?

A I recommend the Commission increase Ameren Missouri's estimated $3.0 million RSG MWP Margins by $2.5 million to correct the misapplication of the margin percentage, presented in Schedule NLP-1. The margin percentage identified by the Company was calculated in the previous rate case and based on the use of Total RSG and Deviation Revenues. In this proceeding, the Company is proposing to use MISO RSG MWPs net of Price Volatility and Net Regulation Adjustment payments. The RSG MWP Revenue amount and the resulting RSG MWP Margin amount need to be updated for the 12 months ending December 31, 2014 as part of the Company's true-up in this case.

Q PLEASE EXPLAIN HOW YOU REMOVED THE EFFECTS OF THE POLAR VORTEX FROM THE MISO CHARGE TYPES INCORPORATED INTO ACCOUNT 447 REVENUES INCLUDED IN THE NBEC.

A Ms. Moore's workpaper supporting the NBEC calculation ("UE_DIR-UE_DIR_004-Att-Ameren Missouri NBEC.xlsx") includes the twelve months of MISO revenues incorporated into the NBEC. I removed the revenues and expenses incurred during Polar Vortex period from the data. I then arrived at my adjusted levels by arithmetically averaging the remaining nine months of data and annualizing the result by multiplying by a factor of twelve-ninths, as presented in Schedule NLP-1. The result of this calculation is a net increase in Other Sales Revenues of approximately $1.1 million.

Q PLEASE ELABORATE ON YOUR THIRD ADJUSTMENT.

A My third adjustment is adding line items for Bilateral Off-System Energy Sales Margins and financial Swap Margins. Bilateral Off-System Energy Sales Margins were first discussed in Case No ER-2011-0028 and were subsequently added into the determination of the NBEC in Case No. ER-2012-0166.[10] Similarly, financial Swap Margins were also were added into the determination of the NBEC in Case No. ER-2012-0166.[11]

[10]Bilateral Off-System Energy Sales Margins appear as an explicit line item in 4-final exhibit c fuel stipulation – nbec per company resulting from the NON-UNANIMOUS STIPULATION AND AGREEMENT REGARDING CLASS KILOWATT-HOURS, REVENUES AND BILLING DETERMINANTS, NET BASE ENERGY COSTS, AND FUEL ADJUSTMENT CLAUSE TARIFF SHEETS.

[11]Financial Swaps appear as a explicit line item in 4-final exhibit c fuel stipulation – nbec per company resulting from the NON-UNANIMOUS STIPULATION AND AGREEMENT REGARDING CLASS KILOWATT-HOURS, REVENUES AND BILLING DETERMINANTS, NET BASE ENERGY COSTS, AND FUEL ADJUSTMENT CLAUSE TARIFF SHEETS.

D.1 Bilateral Off-System Energy Sales Margins

Q PLEASE EXPLAIN THE TERM "BILATERAL OFF-SYSTEM ENERGY SALES MARGINS."

A "Bilateral Off-System Energy Sales Margins" is a term first introduced in Case No. ER-2011-0028. It refers to the off-system energy sales margins Ameren Missouri has been successful at earning from bilateral sales that are in excess of those margins that Ameren Missouri would have earned by just selling the energy into the MISO day-ahead and Real-Time energy market.[12] These additional margins are not reflected in the normalized test year production cost runs because those runs assume Ameren Missouri makes all of its off-system energy sales into the MISO day-ahead energy market. These additional margins must be estimated outside of the production cost modeling and incorporated into the Other Sales Revenues component of Ameren Missouri's NBEC.

Q HAS AMEREN MISSOURI INCLUDED ANY "BILATERAL OFF-SYSTEM ENERGY SALES MARGINS" IN ITS PROPOSED NBEC?

A No. In effect, Ameren Missouri is assuming any bilateral energy sales it makes will likely be at sales prices that average to the same prices at which it makes off-system energy sales in its normalized test year production cost run. However, this is not a reasonable assumption.

Q PLEASE EXPLAIN WHY THIS IS AN UNREASONABLE ASSUMPTION.

A There are two reasons. First, if over the long-term the margins from bilateral energy sales were equal to or less than those made by simply selling into the MISO

[12]Bilateral Sales are sales of wholesale electric energy to a counterparty for an agreed upon fixed price.

day-ahead and Real-Time energy markets, Ameren Missouri likely would have long ago ceased making bilateral sales of electric energy in order to produce the highest return for its shareholders. Second, we reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) E data ("3.190 Data") submittals, which were provided to MIEC for November 2011 and October 2014. From that review, we determined that Ameren Missouri, during that 36-month period, did in fact earn off-system energy sales margins from bilateral sales to third-parties that were greater than what Ameren Missouri would have earned by simply selling that energy into the MISO day-ahead and Real-Time energy markets.

Q PLEASE EXPLAIN HOW YOU WERE ABLE TO DETERMINE FROM THE 3.190 DATA THAT AMEREN MISSOURI HAS BEEN EARNING MARGINS FROM BILATERAL OFF-SYSTEM ENERGY SALES IN EXCESS OF THE MARGINS FROM ENERGY SALES INTO THE MISO DAY-AHEAD AND REAL-TIME ENERGY MARKETS.

A The best place to start this explanation is to discuss how Ameren Missouri clears its generation, load and bilateral sales in the MISO day-ahead energy market.

Q WHY ARE YOU FOCUSING ON THE DAY-AHEAD MARKET?

A The normalized test year production cost runs only simulate the day-ahead market. Ameren Missouri separately accounts for its interactions with MISO in the MISO Real-Time energy market through its proposed net Load and Generation Forecasting Deviation cost adder that Ameren Missouri includes in the Other Fuel and Purchased Power Costs component of its NBEC.

Q HOW DOES AMEREN MISSOURI CLEAR ITS GENERATION, LOAD AND BILATERAL SALES IN THE MISO DAY-AHEAD ENERGY MARKET?

A Ameren Missouri offers all of its generation into the MISO day-ahead market and bids its forecasted load into the MISO day-ahead market. When Ameren Missouri's cleared generation MWh in a given hour exceed its cleared load MWh in that hour, Ameren Missouri has a net off-system energy sale equal to the difference between the cleared generation and load MWh. If Ameren Missouri has no bilateral energy sales transactions in that hour, the total off-system energy sales revenue earned by Ameren Missouri for that hour will be equal to the off-system energy sales MWh multiplied by the day-ahead LMP associated with the generators that produced those off-system energy sales MWh. These are the same off-system energy revenues that are being estimated in the normalized test year production cost runs that are performed to determine Ameren Missouri's Net Fuel Cost.

Q WHAT HAPPENS IN AN HOUR IN WHICH AMEREN MISSOURI DOES HAVE A BILATERAL ENERGY SALES TRANSACTION IN THE MISO DAY-AHEAD MARKET?

A There is an opportunity to earn additional off-system energy sales revenues from that bilateral transaction. The bilateral energy sales transaction is scheduled and cleared in the MISO day-ahead energy market. The cleared bilateral energy sales transaction requires Ameren Missouri to incur a <u>charge</u> equal to the MWh of the transaction multiplied by the day-ahead LMP associated with the delivery point of the bilateral transaction. This charge will be offset by the revenue associated with the bilateral transaction that Ameren Missouri is receiving from the buyer of energy under the transaction. When the bilateral contract price paid by the buyer to Ameren

Missouri equals the LMP at the delivery point, Ameren Missouri receives no off-system energy sales margins in excess of what it is paid by MISO (i.e., Bilateral Off-System Energy Sales Margins are zero). Effectively, this is what Ameren Missouri has assumed in its filing -- it will receive no additional margins by selling energy bilaterally rather than into the MISO day-ahead and Real-Time energy markets.

Q WHAT IF THE BILATERAL SALES PRICE IS GREATER THAN THE LMP AT THE DELIVERY POINT?

A Ameren Missouri will earn a Bilateral Off-System Energy Sales Margin equal to the MWh of the transaction in that hour times the difference between the contract price paid by the buyer and the LMP paid by Ameren Missouri to MISO for the transaction.

Q WHAT IF THE BILATERAL SALES PRICE IS LESS THAN THE LMP AT THE DELIVERY POINT?

A Ameren Missouri will incur a negative Bilateral Off-System Energy Sales Margin equal to the MWh of the transaction in that hour times the difference between the LMP paid by Ameren Missouri to MISO for the transaction and the contract price paid by the buyer to Ameren Missouri.

Q HAVE YOU BEEN ABLE TO ESTIMATE A NORMALIZED LEVEL OF NET BILATERAL OFF-SYSTEM ENERGY SALES MARGINS?

A Yes. Using Ameren Missouri's 3.190 Data for November 2011 through October 2014, for all of Ameren Missouri's bilateral energy sales transactions, we calculated the difference each hour between contract revenue earned by Ameren Missouri and the

LMP at the delivery point paid by Ameren Missouri to MISO or PJM. We algebraically summed these hourly values to get Ameren Missouri's net Bilateral Off-System Energy Sales Margins for this 36-month period. We then annualized this sum to a normalized value by dividing it by three. These calculations, which are summarized in Schedule NLP-3, yielded a normalized net Bilateral Off-System Energy Sales Margin of approximately $1.35 million per year.

Q DID YOU ADJUST YOUR NORMALIZED LEVEL OF BILATERAL OFF-SYSTEM ENERGY SALES MARGINS TO REMOVE THE EFFECTS OF THE POLAR VORTEX?

A Yes. Similar to the way Mr. Haro removed the data from the Polar Vortex period when he calculated his normalized electric market prices, I removed this data from consideration when calculating my normalized level of Bilateral Off-System Energy Sales Margins.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION IN REGARD TO THIS ISSUE?

A I recommend the Commission include approximately $1.35 million of net Bilateral Off-System Energy Sales Margins in the Other Sales Revenues component of Ameren Missouri's proposed NBEC. This will reduce Ameren Missouri's NBEC and revenue requirement by $1.35 million.

Q YOUR CALCULATION IS BASED ON EXAMINING THE 36 MONTHS ENDING OCTOBER 31, 2014. WOULD IT BE REASONABLE TO UPDATE THIS CALCULATION FOR THE 36 MONTHS ENDING DECEMBER 31, 2014 (THE END OF THE TRUE-UP PERIOD)?

A Yes, it would be reasonable to update the value at the end of the true-up period in this proceeding.

D.2 Swap Margins

Q PLEASE EXPLAIN THE TERM "SWAP MARGINS."

A "Swap Margins" are the net proceeds from financial bilateral contracts that Ameren Missouri enters into to hedge wholesale market prices for electric energy. A swap is a financial contract where one party exchanges a fixed price at a defined hub for a floating index price at that same hub. An example would be a hypothetical 50 MW on-peak day-ahead swap at Indiana Hub where a counterparty agrees to pay Ameren Missouri a fixed $ per MWh price for 50 MW of volume in exchange for Ameren Missouri paying the counterparty an hourly revenue stream equal to the MISO day-ahead LMP for Indiana Hub for 50 MW of volume.

Q HAS AMEREN MISSOURI INCLUDED ANY "SWAP MARGINS" IN ITS PROPOSED NBEC?

A No. In effect, Ameren Missouri is assuming any financial bilateral contracts it enters into will likely be at fixed prices that average to the same price as the average LMP. However, this is not a reasonable assumption.

Q PLEASE EXPLAIN WHY THIS IS AN UNREASONABLE ASSUMPTION.

A There are two reasons. First, if over the long-term there was no net benefit from swaps, Ameren Missouri likely would have long ago ceased entering into swaps. Second, we reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) E data ("3.190 Data") submittals, which report on the Swap Margins and were provided to MIEC for November 2011 through October. From that review, we were able to determine that Ameren Missouri over the 36-month month period of November 2011 through October 2014 did in fact earn a significant amount of net margins from swaps.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THIS ISSUE?

A I recommend that the Commission include approximately $3.84 million of net Swap Margins in the Other Sales Revenues component of Ameren Missouri's proposed NBEC. As shown in Schedule NLP-4, this is the normalized annual level of these margins for the 36 months ending October 31, 2014. This will reduce Ameren Missouri's NBEC and revenue requirement by $3.84 million.

Q DID YOU ADJUST YOUR NORMALIZED LEVEL OF SWAP MARGINS TO REMOVE THE EFFECTS OF THE POLAR VORTEX?

A Yes. Similar to the way Mr. Haro removed the data from the Polar Vortex period when he calculated his normalized electric market prices, I removed this data from consideration when calculating my normalized level of Swap Margins.

Q YOUR CALCULATION IS BASED ON EXAMINING THE 36 MONTHS ENDING OCTOBER 31, 2014. WOULD IT BE REASONABLE TO UPDATE THIS CALCULATION FOR THE 36 MONTHS ENDING DECEMBER 31, 2014 (THE END OF THE TRUE-UP PERIOD)?

A Yes, it would be reasonable to update the value at the end of the true-up period in this proceeding to the extent the appropriate data becomes available.

Q SHOULD AMEREN MISSOURI'S OTHER SALES REVENUES VALUE BE FURTHER UPDATED THROUGH DECEMBER 31, 2014?

A Yes. All of the values that make up Ameren Missouri's Other Sales Revenues should be updated through the end of December 31, 2014.

D.3 Summary of Recommended Adjustments to Ameren Missouri's Proposed Level of Other Sales Revenues

Q CAN YOU PLEASE SUMMARIZE ALL OF YOUR PROPOSED ADJUSTMENTS AT THIS TIME TO AMEREN MISSOURI'S PROPOSED LEVEL OF OTHER SALES REVENUES?

A Yes. My total adjustment at this time is a net $8.8 million increase to Ameren Missouri's proposed level of Other Sales Revenues, which would result in a reduction of the same amount to Ameren Missouri's NBEC and Revenue Requirement. The $8.8 million net increase in Other Sales Revenues consists of a $3.6 million increase in revenues due to updated MISO market settlement revenue values, a $1.35 million increase in revenues due to Bilateral Off-System Sales Margins and a $3.84 million increase in revenues due to Swap Margins.

III. Conclusions and Recommendations

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission reduce Ameren Missouri's proposed NBEC from its original filing in this case (and, thus, its original filing revenue requirement) by at least $24.0 million. This $24 million addresses: (i) the $6.35 million adjustment of Net Fuel Cost identified in Mr. Andrews' direct testimony; (ii) the $8.85 million adjustment to Other Fuel and Purchased Power Costs that I have identified herein; and (iii) the $8.8 million adjustment to Other Sales Revenues that I have identified herein.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of Nicholas L. Phillips

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas L. Phillips. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from the Washington University in St. Louis/University of Missouri-St. Louis joint engineering program in 2010 where I received a Bachelor of Science degree in Electrical Engineering. In 2012 I received the degree of Master of Engineering in Electrical Engineering with a concentration in Electric Power and Energy Systems from Iowa State University of Science and Technology. I am currently pursuing a Master of Science Degree in Computational Finance and Risk Management through the University of Washington. I am a member of the Power and Energy Society of the Institute of Electrical and Electronics Engineers.

I joined BAI as an intern in 2009 and upon graduation, I accepted a position with BAI as an Associate Engineer. In January of 2012, I was promoted to the position of Associate Consultant, in January of 2013 I was promoted to the position of Consultant at BAI, and in January of 2014 I was promoted to my current position of Senior Consultant at BAI. While at BAI, I have been involved with numerous regulated and competitive electric service issues. These have included transmission planning, resource planning, electric price forecasting, load forecasting, cost of service, combined heat and power steam costs and power procurement. This has involved the performance of power flow, production cost, transmission line routing, cost of service and other analysis to address these issues.

Prior to joining BAI, through the department of Electrical and Computer Engineering and the Medical School at Washington University in St. Louis, I aided in preliminary research focusing on the use of ultrasound as a mechanism for in vitro localized thermometry.

BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have attended seminars concerned with rate design, cost of service, and wind integration. My completed coursework includes classes in Power & Energy System

Planning, Power System Operation & Control (Steady State Analysis), Economic Systems for Electric Power Planning, Power System Dynamics, Electromechanical Wind Energy Conversion & Grid Integration, Nuclear Engineering & Radiation Theory, Reliability, Linear System Theory, System Engineering Analysis, Allocation Mechanisms, Capital Markets and Data for Computational Finance, Investment Science, R Programming for Quantitative Finance, Quantitative Risk Measurement, Portfolio Benchmarking and Analysis, Credit Risk Management, and Options and Derivatives.

Topics covered by these classes include but are not limited to Economic Dispatch, Unit Commitment, Production Cost Modeling, Capacity Expansion Planning, Transmission Planning, Power Flow Analysis, Security Constrained Optimal Power Flow, Transient and Dynamic Stability, Wholesale Electricity Markets, Nuclear Energy, Reliability Studies as well as experience with PLEXOS, an industry leading combined production cost and capacity/transmission expansion model. Additionally, MISO professionals presented a series of nine lectures discussing their approach to the planning process and use of production costing, capacity/transmission expansion planning, and other software including PSS/E, PROMOD IV, Strategist, MARS, and EGEAS.

Q **HAVE YOU PREVIOUSLY FILED TESTIMONY WITH A REGULATORY COMMISSION?**

A Yes. I have filed testimony with the Public Service Commissions of Kansas, Michigan, Missouri, Wisconsin and the New Mexico Public Regulation Commission, in numerous proceedings concerning production cost modeling, net fuel costs, purchase power expense, off-system sales, coal commodity and transportation contracts, cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, revenue requirements, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, environmental compliance, cost recovery, economic dispatch, and various other items.

\\Doc\Shares\ProlawDocs\MED\9913\Testimony-BAI\269253.docx

Case No. ER-2014-0258

Adjustments to MISO Market Settlement Charges

($)

Non-Energy Actual Charges	FERC Major Revenue/Expense	APR 2013	MAY 2013	JUN 2013	JUL 2013	AUG 2013	SEP 2013	OCT 2013	NOV 2013	DEC 2013	JAN 2014	FEB 2014	MAR 2014	Total	Polar Vortex Adj. Total
MISO Day 2															
REVENUES															
RSG / Deviation	447 Revenue	(791,248)	(670,615)	(1,169,556)	(2,148,790)	(2,959,863)	848,993	(364,174)	(599,150)	(587,450)	(645,996)	(861,228)	(854,669)	$ (10,803,746)	$ (11,255,804)
Inadvertent	447 Revenue	(6,677)	(605)	(547)	(3,402)	(1,276)	229	(1,297)	(5,549)	(1,891)	(5,047)	(2,549)	(2,325)	$ (30,934)	$ (28,019)
Total MISO Day 2 Revenues:		$ (797,925)	$ (671,220)	$ (1,170,103)	$ (2,152,192)	$ (2,961,139)	$ 849,222	$ (365,471)	$ (604,699)	$ (589,341)	$ (651,043)	$ (863,776)	$ (856,993)	$ (10,834,680)	$ (11,283,823)
EXPENSES															
Losses	555 Expense	1,465,853	1,732,210	1,566,360	1,803,540	1,906,336	1,626,506	1,598,086	1,476,731	2,253,932	3,533,894	2,927,424	2,032,050	$ 23,922,923	$ 20,572,740
RNU	555 Expense	928,521	827,857	1,155,169	697,862	324,162	349,948	764,523	1,509,450	3,393,624	(1,393,936)	1,686,271	479,932	$ 10,723,386	$ 13,268,157
RSG / Deviation	555 Expense	740,885	672,635	350,792	498,356	618,269	138,510	269,051	196,560	572,738	489,149	755,204	1,946,248	$ 7,248,398	$ 5,410,396
Congestion & FTR & ARR	555 Expense	(708,479)	(779,884)	(400,731)	(260,149)	(345,847)	(316,035)	(392,687)	(387,638)	(364,673)	(369,138)	(369,138)	(345,524)	$ (5,039,923)	$ (5,274,831)
Congestion & FTR & ARR	555 Expense	3,067,800	(152,590)	1,296,081	800,330	1,058,366	985,470	684,475	3,150,734	2,061,115	474,552	2,772,544	672,932	$ 16,871,807	$ 17,269,040
Congestion & FTR & ARR	555 Expense	(3,950,643)	(107,508)	(2,397,960)	(941,709)	(1,370,871)	(1,187,550)	(1,294,598)	(5,630,949)	(5,373,405)	880,591	(3,865,199)	(364,177)	$ (25,603,978)	$ (29,673,590)
Congestion & FTR & ARR Subtotal		$ (1,591,322)	$ (1,039,982)	$ (1,502,611)	$ (401,528)	$ (658,352)	$ (518,115)	$ (1,002,811)	$ (2,867,852)	$ (3,676,963)	$ 986,005	$ (1,461,793)	$ (36,770)	$ (13,772,094)	$ (17,679,382)
Inadvertent	555 Expense	6,127	21,420	18,572	(36,369)	96,019	161,977	39,065	(55,760)	(30,194)	(56,696)	26,110	160,703	$ 350,974	$ 294,475
MISO Day 2 Expenses for NBFC:		1,550,064	2,214,140	1,588,282	2,561,862	2,286,434	1,758,826	1,667,915	259,129	2,513,137	3,558,417	3,933,217	4,582,163	$ 28,473,586	$ 21,866,387
Admin	575 Expense	885,578	785,984	898,726	692,922	685,402	826,219	744,957	1,081,069	373,398	640,351	645,223	595,780	$ 8,855,609	$ 9,299,007
Admin	555 Expense	102,834	103,359	113,034	105,221	100,707	105,924	99,739	164,748	62,494	95,643	104,824	109,184	$ 1,267,711	$ 1,277,413
Admin Subtotal		$ 737,774	$ 828,842	$ 815,038	$ 988,412	$ 889,343	$ 1,011,760	$ 798,143	$ 786,109	$ 932,143	$ 844,696	$ 1,245,817	$ 435,892	$ 10,313,969	$ 10,383,419
Total MISO Day 2 Expenses:		$ 841,247	$ 1,508,741	$ 2,190,442	$ 2,295,349	$ 1,654,670	$ 1,685,051	$ 2,348,207	$ 3,000,249	$ 2,520,426	$ 3,406,557	$ 3,532,251	$ 2,194,718	$ 27,177,908	$ 24,059,176
Ancillary Services															
REVENUES															
ASMP	447 Expense	136,496	126,157	123,233	60,422	147,592	1,980	26,441	48,245	47,993	129,412	134,934	105,844	$ 1,088,750	$ 958,078
RFRS	447 Revenue	(467,620)	(539,012)	(427,670)	(235,082)	(489,088)	25,751	(407,294)	(378,863)	(262,161)	(375,761)	(432,947)	(306,122)	$ (4,295,868)	$ (4,241,384)
SPRS	447 Revenue	(244,310)	(166,593)	(147,567)	(411,932)	(664,976)	(20,849)	(535,921)	(331,300)	(426,106)	(83)	(301,316)	(375,148)	$ (3,626,101)	$ (3,932,739)
SURS	447 Revenue	(159,657)	(432,641)	(351,209)	(474,855)	(919,004)	(62,868)	(565,524)	(447,214)	(223,899)	(47,510)	(295,999)	(369,042)	$ (4,349,423)	$ (4,849,162)
Total Ancillary Services Revenues:		$ (735,091)	$ (1,012,089)	$ (803,213)	$ (1,061,447)	$ (1,925,476)	$ (55,986)	$ (1,482,298)	$ (1,109,131)	$ (864,174)	$ (293,942)	$ (895,328)	$ (944,467)	$ (11,182,641)	$ (12,065,206)
EXPENSES															
ASMP	555 Expense													$ -	$ -
RFRA	555 Expense	-	-	-	-	-	-	-	-	-	-	-	-	$ -	$ -
RFRS	555 Expense	142,608	166,626	139,091	102,958	109,506	112,565	117,349	129,040	210,930	74,940	160,969	131,839	$ 1,598,422	$ 1,640,898
SPRS	555 Expense	229,866	295,319	235,680	190,586	181,574	227,029	202,479	182,900	157,434	87,767	174,916	146,871	$ 2,312,421	$ 2,537,155
SURS	555 Expense	66,290	108,915	122,480	108,554	93,579	151,206	172,985	141,128	99,211	(28,125)	60,336	82,462	$ 1,179,021	$ 1,419,129
Total Ancillary Services Expenses:		$ 438,765	$ 570,860	$ 497,251	$ 402,099	$ 384,659	$ 490,799	$ 492,812	$ 453,068	$ 467,574	$ 134,583	$ 396,221	$ 361,173	$ 5,089,863	$ 5,597,182

Net Expense/(Revenue)

Source: UE_DIR-UE_DIR_004-Att-Ameren Missouri NBEC.xls›

Total RSG and Deviation Revenues	10,803,746	11,255,804
Less Price Volatility and Net Regulation Adjustments	(4,888,828)	
Revenue Sufficiency Guarantee Make Whole Payment	5,914,918	11,255,804
Percent of Make Whole Payment Margin	51%	51%
Make Whole Payment Margins	3,016,608	5,740,460

Case No. ER-2014-0258
Load Forecast and Generation Deviation Expense

Year	Month	Load Forecast Error Expense ($)	Generation Deviation Expense ($)
2011	11	19,252	(1,176,540)
2011	12	210,765	(911,030)
2012	1	99,437	(874,922)
2012	2	(24,263)	(306,987)
2012	3	68,958	(419,078)
2012	4	80,091	(552,823)
2012	5	460,755	(673,188)
2012	6	674,437	(238,170)
2012	7	1,754,630	(802,710)
2012	8	656,568	(61,094)
2012	9	182,854	(176,929)
2012	10	59,880	(355,651)
2012	11	9,375	(943,909)
2012	12	62,386	(667,794)
2013	1	241,100	(267,406)
2013	2	99,196	(397,531)
2013	3	272,412	(836,261)
2013	4	(188,725)	(169,527)
2013	5	163,551	(670,229)
2013	6	553,887	(712,102)
2013	7	64,019	(56,655)
2013	8	301,699	68,614
2013	9	322,376	(127,482)
2013	10	(36,875)	(73,155)
2013	11	138,812	(882,887)
2013	12	252,378	(570,349)
2014	1	679,791	340,559
2014	2	435,481	(272,237)
2014	3	611,446	(1,172,476)
2014	4	178,874	(490,702)
2014	5	168,597	(293,439)
2014	6	420,249	(877,406)
2014	7	324,633	(46,110)
2014	8	61,853	(64,327)
2014	9	185,634	(106,090)
2014	10	51,987	(241,732)
2 Year Ave	1	170,268	(571,164)
2 Year Ave	2	37,466	(352,259)
2 Year Ave	3	170,685	(627,670)
3 Year Ave	4	23,413	(404,351)
3 Year Ave	5	264,301	(545,619)
3 Year Ave	6	549,524	(609,226)
3 Year Ave	7	714,428	(301,825)
3 Year Ave	8	340,040	(18,936)
3 Year Ave	9	230,288	(136,833)
3 Year Ave	10	24,997	(223,513)
3 Year Ave	11	55,813	(1,001,112)
3 Year Ave	12	175,176	(716,391)
	Total	2,756,400	(5,508,899)
	Net		(2,752,498)

Case No. ER-2014-0258
Bilateral Off-System Energy Sale Margins

Year	Month	Margin ($)
2011	11	93,151
2011	12	74,690
2012	1	151,175
2012	2	34,656
2012	3	95,402
2012	4	76,844
2012	5	395,909
2012	6	113,241
2012	7	(414,681)
2012	8	296,296
2012	9	145,418
2012	10	164,328
2012	11	99,059
2012	12	56,734
2013	1	167,856
2013	2	262,838
2013	3	207,540
2013	4	(664,063)
2013	5	(41,021)
2013	6	714,650
2013	7	499,937
2013	8	645,899
2013	9	12,814
2013	10	17,151
2013	11	9,700
2013	12	19,447
2014	1	2,451
2014	2	(15,035)
2014	3	829
2014	4	6,240
2014	5	16,334
2014	6	66,192
2014	7	14,215
2014	8	258,441
2014	9	1,441
2014	10	918
2 Year Ave	1	159,515
2 Year Ave	2	148,747
2 Year Ave	3	151,471
3 Year Ave	4	(193,660)
3 Year Ave	5	123,741
3 Year Ave	6	298,028
3 Year Ave	7	33,157
3 Year Ave	8	400,212
3 Year Ave	9	53,224
3 Year Ave	10	60,799
3 Year Ave	11	54,380
3 Year Ave	12	38,090
	Total	1,327,704

Case No. ER-2014-0258
Financial Swap Margins

Year	Month	Margin ($)
2011	11	1,247,037
2011	12	1,301,604
2012	1	2,146,480
2012	2	2,478,831
2012	3	3,353,713
2012	4	2,927,830
2012	5	1,703,703
2012	6	(80,735)
2012	7	(5,108,049)
2012	8	(1,272,671)
2012	9	2,592,879
2012	10	606,550
2012	11	(728,245)
2012	12	1,234,710
2013	1	705,592
2013	2	795,064
2013	3	(296,958)
2013	4	(770,272)
2013	5	(586,240)
2013	6	202,587
2013	7	(657,515)
2013	8	(697,889)
2013	9	(154,928)
2013	10	(636,950)
2013	11	292,650
2013	12	(185,832)
2014	1	(9,588,528)
2014	2	(4,539,024)
2014	3	(3,004,043)
2014	4	(1,120,708)
2014	5	(1,636,679)
2014	6	(344,936)
2014	7	(162,540)
2014	8	(237,813)
2014	9	(104,473)
2014	10	123,904
2 Year Ave	1	1,426,036
2 Year Ave	2	1,636,947
2 Year Ave	3	1,528,377
3 Year Ave	4	345,617
3 Year Ave	5	(173,072)
3 Year Ave	6	(74,361)
3 Year Ave	7	(1,976,035)
3 Year Ave	8	(736,124)
3 Year Ave	9	777,826
3 Year Ave	10	31,168
3 Year Ave	11	270,481
3 Year Ave	12	783,494
	Total	3,840,353