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Witness: Nicholas L. Phillips  
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Sponsoring Party: MIEC  
Case No.: ER-2014-0258  
Date Testimony Prepared: December 5, 2014

**BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MISSOURI**

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**In the Matter of Union Electric Company,  
d/b/a Ameren Missouri's Tariff to Increase  
Its Revenues for Electric Service**

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**Case No. ER-2014-0258**

Direct Testimony and Schedules of

**Nicholas L. Phillips**

On behalf of

**Missouri Industrial Energy Consumers**

December 5, 2014



Project 9913

**BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MISSOURI**

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In the Matter of Union Electric Company, )  
d/b/a Ameren Missouri's Tariff to Increase )  
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\_\_\_\_\_)

Case No. ER-2014-0258

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

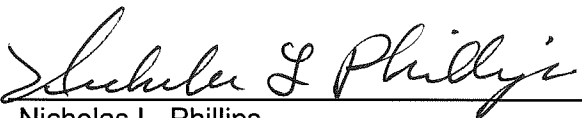
**Affidavit of Nicholas L. Phillips**

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

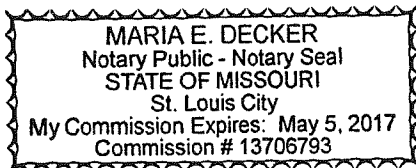
1. My name is Nicholas L. Phillips. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

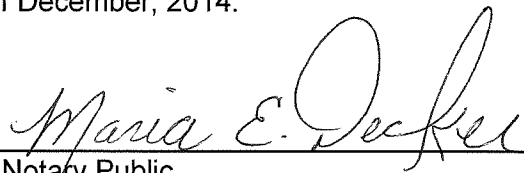
2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.

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

Subscribed and sworn to before me this 4<sup>th</sup> day of December, 2014.



  
\_\_\_\_\_  
Notary Public

**BEFORE THE PUBLIC SERVICE COMMISSION  
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) **Case No. ER-2014-0258**  
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**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").

1    **Q     HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE**  
2    **MISSOURI PUBLIC SERVICE COMMISSION (“COMMISSION”)?**

3    A     Yes. I testified in Case Nos. ER-2012-0166, ER-2012-0174, and ER-2012-0175  
4         before the Commission regarding fuel cost, purchase power expense, and off-system  
5         sales revenue.

6    **Q     WHAT IS THE SUBJECT OF YOUR TESTIMONY?**

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

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

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

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

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

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

9 Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

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

17 **II. NBEC**

18 Q PLEASE EXPLAIN THE TERM NBEC.

19 A Ameren Missouri's NBEC is the portion of Ameren Missouri's revenue requirement  
20 that is tracked through its Fuel Adjustment Clause. The NBEC established in this  
21 proceeding will set the base level of energy expense Ameren Missouri is authorized  
22 to collect through base rates. The FAC tracks and reconciles prudently incurred

1 deviations in actual net energy cost above or below this established base level. The

2 NBEC consists of three major components:

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

6 Plus

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

12 Less

13 3. **Other Sales Revenues** – Off-system sales of capacity, MISO ancillary service  
14 revenues and MISO Day 2 revenues (including MISO RSG Make Whole Payment  
15 Margins).<sup>1</sup>

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

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

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

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<sup>1</sup>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.

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

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

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

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



1 A. *Adjustments to Net Fuel Cost*

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

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

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

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

14 B. *The Polar Vortex*

15 **Q PLEASE DESCRIBE THE POLAR VORTEX.**

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

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<sup>2</sup>Direct Testimony of Jamie Haro at Page 8.

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

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

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

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

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

18 A No. After reviewing Mr. Peters' workpapers, the adjustment Mr. Haro made to the  
19 electric market prices actually replaced the prices from the three-month Polar Vortex  
20 period with the average prices of the applicable peak period by month for January  
21 2012 – March 2012 and January 2013 – March 2013 (not just January 2012 – March  
22 2012 as Mr. Haro indicated in his testimony).

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<sup>4</sup>Direct Testimony of Jamie Haro at Page 8.

<sup>5</sup>Direct Testimony of Jaime Haro at Pages 7-8.

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

3 A No.

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

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

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

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

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

5 A Yes. I have calculated two adjustments to Ameren Missouri's original filed values for  
6 the Other Fuel and Purchased Power Costs component of the NBEC. First, I have  
7 removed the effects of the Polar Vortex from Ameren Missouri's MISO Day 2 Account  
8 555 Market Charges and the Ancillary Service Account 555 Market Charges and  
9 annualized the remaining nine months of test year charges to estimate a Polar Vortex  
10 adjusted amount of expenses to include in base rates. My second adjustment is to  
11 add a line item for net Load and Generation Forecasting Deviation error expense.

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

15 A Ms. Moore's workpaper supporting the NBEC calculation ("UE\_DIR-UE\_DIR\_004-Att-  
16 Ameren Missouri NBEC.xlsx") includes the 12 months (April 2013 – March 2014) of  
17 MISO expenses and revenues incorporated into the NBEC. I propose removing the  
18 expenses and revenues incurred during Polar Vortex period from the data. I then  
19 arrive at my adjusted levels by arithmetically averaging the remaining nine months of  
20 data and annualizing the result by multiplying by a factor of twelve-ninths, as  
21 presented in Schedule NLP-1. The result of this calculation is a net reduction in other  
22 fuel and purchase power expense of approximately \$6.1 million.

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

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

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

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

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

10 A It is unclear. No specific line item exists for net Load and Generation Forecasting  
11 Deviation in Schedule LMM-17; however, the supporting workpaper indicates  
12 Company witness Mark Peters provided an estimate of \$0. In MIEC's Data Request  
13 15.1 to Ameren Missouri, I asked that the Company provide a workpaper, similar to  
14 Mr. Peters' workpaper used in Case No. ER-2012-0166 to support the net Load and  
15 Generation Forecasting Deviation error estimates. The Company responded to  
16 MIEC's Data Request 15.1 stating that no such calculation has been performed in this  
17 case. I have also prepared my own estimate of net Load and Generation Forecasting  
18 Deviation error expense.

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<sup>6</sup>Direct Testimony of Mark Peters, Case No ER-2012-0166 at Pages 10-11.

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

4 A We reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) E data ("3.190 Data")  
5 submittals, which were provided to MIEC for November 2011 through October 2014  
6 through a combination of data request responses and non-unanimous stipulations in  
7 Case Nos. ER-2010-0036 and ER-2011-0028. Included in this data are Real-Time  
8 Generation Deviations for each of Ameren Missouri's generators on an hourly basis,  
9 as well as Ameren Missouri's Real-Time hourly load deviations. I extracted the  
10 generation deviations for each of Ameren Missouri's non-CTG generating units for the  
11 36-month period from November 1, 2011 through October 31, 2014. I then calculated  
12 the monthly generation deviation revenue for each month in the 36 month period by  
13 multiplying the Real-Time Generation Deviation by the difference between the  
14 Real-Time and Day-Ahead LMPs for the appropriate generator node. I performed a  
15 similar calculation for Ameren Missouri's load deviation costs. I then normalized the  
16 costs and revenues by removing the three Polar Vortex months and annualized the  
17 remainder of the data, consistent with the Company's treatment of electric market  
18 prices.<sup>7</sup> The net result is \$2.75 million in additional revenue, which needs to be  
19 reflected in the NBEC, is presented in Schedule NLP-2.

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<sup>7</sup>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.

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

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

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

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

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

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

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1 D. *Adjustments to Other Sales Revenues*

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

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

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

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

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

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<sup>8</sup>Workpaper "UE\_DIR-UE\_DIR\_004-Att-Ameren Missouri NBEC.xlsx".

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

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

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

14 A Yes. Ms. Moore's workpapers identify approximately \$5.9 million of MISO RSG MWP  
15 during the test year for this proceeding. This \$5.9 million is the result of netting  
16 \$4.9 million in Price Volatility and Net Regulation Adjustment from \$10.8 million in  
17 Total RSG and Deviation Revenues.

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

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

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<sup>9</sup>Economic merit order refers to the dispatch the next lowest cost resource.

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

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

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

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

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

1 Q PLEASE EXPLAIN HOW YOU REMOVED THE EFFECTS OF THE POLAR  
2 VORTEX FROM THE MISO CHARGE TYPES INCORPORATED INTO ACCOUNT  
3 447 REVENUES INCLUDED IN THE NBEC.

4 A Ms. Moore's workpaper supporting the NBEC calculation ("UE\_DIR-UE\_DIR\_004-Att-  
5 Ameren Missouri NBEC.xlsx") includes the twelve months of MISO revenues  
6 incorporated into the NBEC. I removed the revenues and expenses incurred during  
7 Polar Vortex period from the data. I then arrived at my adjusted levels by  
8 arithmetically averaging the remaining nine months of data and annualizing the result  
9 by multiplying by a factor of twelve-ninths, as presented in Schedule NLP-1. The  
10 result of this calculation is a net increase in Other Sales Revenues of approximately  
11 \$1.1 million.

12 Q PLEASE ELABORATE ON YOUR THIRD ADJUSTMENT.

13 A My third adjustment is adding line items for Bilateral Off-System Energy Sales  
14 Margins and financial Swap Margins. Bilateral Off-System Energy Sales Margins  
15 were first discussed in Case No ER-2011-0028 and were subsequently added into  
16 the determination of the NBEC in Case No. ER-2012-0166.<sup>10</sup> Similarly, financial  
17 Swap Margins were also were added into the determination of the NBEC in Case  
18 No. ER-2012-0166.<sup>11</sup>

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<sup>10</sup>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.

<sup>11</sup>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.

1 *D.1 Bilateral Off-System Energy Sales Margins*

2 **Q PLEASE EXPLAIN THE TERM “BILATERAL OFF-SYSTEM ENERGY SALES**  
3 **MARGINS.”**

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

14 **Q HAS AMEREN MISSOURI INCLUDED ANY “BILATERAL OFF-SYSTEM ENERGY**  
15 **SALES MARGINS” IN ITS PROPOSED NBEC?**

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

20 **Q PLEASE EXPLAIN WHY THIS IS AN UNREASONABLE ASSUMPTION.**

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

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<sup>12</sup>Bilateral Sales are sales of wholesale electric energy to a counterparty for an agreed upon fixed price.

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

10 **Q PLEASE EXPLAIN HOW YOU WERE ABLE TO DETERMINE FROM THE**  
11 **3.190 DATA THAT AMEREN MISSOURI HAS BEEN EARNING MARGINS FROM**  
12 **BILATERAL OFF-SYSTEM ENERGY SALES IN EXCESS OF THE MARGINS**  
13 **FROM ENERGY SALES INTO THE MISO DAY-AHEAD AND REAL-TIME ENERGY**  
14 **MARKETS.**

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

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

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

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

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

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

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

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

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

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

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

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

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

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



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

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

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

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

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

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

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

7 *D.2 Swap Margins*

8 Q PLEASE EXPLAIN THE TERM "SWAP MARGINS."

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

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

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

1 **Q PLEASE EXPLAIN WHY THIS IS AN UNREASONABLE ASSUMPTION.**

2 A There are two reasons. First, if over the long-term there was no net benefit from  
3 swaps, Ameren Missouri likely would have long ago ceased entering into swaps.  
4 Second, we reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) E data  
5 ("3.190 Data") submittals, which report on the Swap Margins and were provided to  
6 MIEC for November 2011 through October. From that review, we were able to  
7 determine that Ameren Missouri over the 36-month month period of November 2011  
8 through October 2014 did in fact earn a significant amount of net margins from  
9 swaps.

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

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

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

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

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

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

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

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

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

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

16 A Yes. My total adjustment at this time is a net \$8.8 million increase to Ameren  
17 Missouri's proposed level of Other Sales Revenues, which would result in a reduction  
18 of the same amount to Ameren Missouri's NBEC and Revenue Requirement. The  
19 \$8.8 million net increase in Other Sales Revenues consists of a \$3.6 million increase  
20 in revenues due to updated MISO market settlement revenue values, a \$1.35 million  
21 increase in revenues due to Bilateral Off-System Sales Margins and a \$3.84 million  
22 increase in revenues due to Swap Margins.

1 **III. Conclusions and Recommendations**

2 **Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

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

10 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

11 **A** Yes.

## Qualifications of Nicholas L. Phillips

1    **Q     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

4    **Q     PLEASE STATE YOUR OCCUPATION.**

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

7    **Q     PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL  
8        EMPLOYMENT EXPERIENCE.**

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

17            I joined BAI as an intern in 2009 and upon graduation, I accepted a position  
18       with BAI as an Associate Engineer. In January of 2012, I was promoted to the  
19       position of Associate Consultant, in January of 2013 I was promoted to the position of  
20       Consultant at BAI, and in January of 2014 I was promoted to my current position of  
21       Senior Consultant at BAI. While at BAI, I have been involved with numerous

**Nicholas L. Phillips**  
**Appendix A**  
**Page 1**

1 regulated and competitive electric service issues. These have included transmission  
2 planning, resource planning, electric price forecasting, load forecasting, cost of  
3 service, combined heat and power steam costs and power procurement. This has  
4 involved the performance of power flow, production cost, transmission line routing,  
5 cost of service and other analysis to address these issues.

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

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

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

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

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

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

**Nicholas L. Phillips**  
**Appendix A**  
**Page 2**

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

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

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

21 **A** Yes. I have filed testimony with the Public Service Commissions of Kansas,  
22 Michigan, Missouri, Wisconsin and the New Mexico Public Regulation Commission, in  
23 numerous proceedings concerning production cost modeling, net fuel costs, purchase  
24 power expense, off-system sales, coal commodity and transportation contracts, cost

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**Appendix A**  
**Page 3**



1 of service, rate base, unit costs, pro forma operating income, appropriate class rates  
2 of return, revenue requirements, integrated resource planning, power plant  
3 operations, fuel cost recovery, regulatory issues, environmental compliance, cost  
4 recovery, economic dispatch, and various other items.

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**Nicholas L. Phillips**  
**Appendix A**  
**Page 4**

Case No. ER-2014-0258  
Adjustments to MISO Market Settlement Charges

(\$)

Non-Energy Actual Charges			FERC Major Revenue/Expense											Total	Polar Vortex Adj. Total	
			APR 2013	MAY 2013	JUN 2013	JUL 2013	AUG 2013	SEP 2013	OCT 2013	NOV 2013	DEC 2013	JAN 2014	FEB 2014	MAR 2014		
<b>MISO Day 2 REVENUES</b>																
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)
<b>Total MISO Day 2 Revenues:</b>			\$ (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)
<b>EXPENSES</b>																
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)
<b>Congestion &amp; FTR &amp; ARR Subtotal</b>			\$ (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
<b>MISO Day 2 Expenses for NBFC:</b>			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
<b>Admin Subtotal</b>			\$ 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
<b>Total MISO Day 2 Expenses:</b>			\$ 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
<b>Ancillary Services REVENUES</b>																
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)
<b>Total Ancillary Services Revenues:</b>			\$ (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)
<b>EXPENSES</b>																
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
<b>Total Ancillary Services Expenses:</b>			\$ 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.xlsx

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**

<u>Year</u>	<u>Month</u>	<u>Margin</u> (\$)
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
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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
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	Total	1,327,704

**Case No. ER-2014-0258**  
**Financial Swap Margins**

<u>Year</u>	<u>Month</u>	<u>Margin</u> (\$)
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
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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
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	Total	3,840,353