Exhibit No.:	
Issue:	Revenue Requirement
Witness:	James R. Dauphinais
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2011-0028
Date Testimony Prepared:	February 8, 2011

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 Annual Revenues for Electric Service	)	**Case No. ER-2011-0028** Tariff No. YE-2011-0166

Direct Testimony and Schedules of

James R. Dauphinais

On behalf of

Missouri Industrial Energy Consumers

NON-PROPRIETARY VERSION

February 8, 2011

BAI
BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9371

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 Annual Revenues for Electric Service	**Case No. ER-2011-0028** Tariff No. YE-2011-0166

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

Affidavit of James R. Dauphinais

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

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by 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 the Missouri Public Service Commission Case No. ER-2011-0028.

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

James R. Dauphinais
James R. Dauphinais

Subscribed and sworn to before me this 8th day of February, 2011.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2013
Commission # 09706793

Maria E. Decker
Notary Public

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<u>Direct Testimony of James R. Dauphinais</u>

<u>I. INTRODUCTION</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and principal of 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 my 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"). Member companies purchase substantial amounts of electric service from Union Electric Company ("Ameren Missouri" or "AmerenUE").

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

A Yes. I have been involved in a number of proceedings before the Commission including, but not limited to, Case Nos. ER-2007-0002, ER-2008-0318 and ER-2010-0036, where I testified in regard to Ameren Missouri's fuel cost and off-system sales.

Q WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A My testimony addresses Ameren Missouri's proposed Net Base Fuel Cost that it proposes to include in its revenue requirement. Specifically, I address the generation capabilities assumed in Ameren Missouri's production cost modeling, Ameren Missouri's Bilateral Off-System Energy Sales Margins and Ameren Missouri's proposed level of Midwest Independent Transmission System Operator, Inc. ("MISO") Revenue Sufficiency Guarantee ("RSG") Make Whole Payment Margins.

My testimony also addresses the level of transmission revenues Ameren Missouri proposes to include as a credit in its revenue requirement.

Finally, I briefly discuss Ameren Missouri's proposed ratemaking treatment in this proceeding of wholesale electric sales to certain municipal electric utilities.

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

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission reduce Ameren Missouri's proposed Net Base Fuel Cost (and, thus, its revenue requirement) by not less than $12.9 million to correct: (i) the unreasonable level of generation capability assumed by Ameren Missouri for the Callaway, Osage and Sioux generation facilities in its normalized test year production cost modeling; (ii) the failure by Ameren Missouri to include an estimate of its bilateral off-system energy sales margins; and (iii) the unreasonable level of MISO RSG Make Whole Payment Margins proposed by Ameren Missouri.

In addition, I recommend that the transmission revenues included as a credit in Ameren Missouri's proposed revenue requirement be adjusted to reflect Ameren Missouri's current FERC-authorized wholesale transmission rates in order to be consistent with Ameren Missouri's inclusion in rate base of all plant in-service by the end of the true-up period. I have estimated this adjustment will raise Ameren Missouri's proposed transmission revenues by $2.9 million, which will in turn lower Ameren Missouri's proposed revenue requirement by the same amount.

In total, I am recommending Ameren Missouri's proposed revenue requirement be lowered by $15.8 million.

II. NET BASE FUEL COST

Q PLEASE EXPLAIN THE TERM NET BASE FUEL COST?

A Ameren Missouri's Net Base Fuel Cost is the portion of Ameren Missouri's revenue requirement that is tracked through its Fuel Adjustment Clause. It consists of three major components:

1. **Net Fuel Cost** – Fuel and purchased power costs for native load and off-system sales, less off-system energy sales revenues, 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 net, net Load and Generation Forecasting Deviation costs, and the cost of purchased power to serve common boundary customers.

Less

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

(Direct Testimony of Weiss at 32-33, Direct Testimony of Finnell at 2 and Direct Testimony of Haro at 3-5).

Q ON WHAT STANDARD SHOULD THE COMMISSION IN THIS PROCEEDING SET AMEREN MISSOURI'S NET BASE FUEL COST COMPONENT OF ITS 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 in this proceeding based on Ameren Missouri's actual costs during the historic test year ending March 31, 2010 adjusted for known and measurable changes from the true-up period that ends February 28, 2011 and normalized to annualize periodic expenses and address abnormalities such as annual swings in weather and commodity market prices.

Q WHAT IS THE TOTAL ANNUAL NET BASE FUEL COST THAT AMEREN MISSOURI IS PROPOSING IN THIS PROCEEDING?

A Ameren Missouri is proposing a Net Base Fuel Cost of approximately $514 million. This consists of a Net Fuel Cost of $465 million plus Other Fuel and Purchased Power Costs of $64 million less Other Sales Revenues of approximately $15 million (Schedule GSW-E17, Direct Testimony of Finnell at 2-3 and Direct Testimony of Haro at 5). As Mr. Weiss indicates, the amount is a $73 million increase from the Net Base

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

Fuel Cost approved by the Commission for Ameren Missouri in Case No. ER-2010-0036 (Direct Testimony of Weiss at 33).

Q PLEASE DESCRIBE YOUR REVIEW OF AMEREN MISSOURI'S PROPOSED NET BASE FUEL COST AMOUNT.

A I reviewed the direct testimony and schedules of Ameren Missouri witnesses Finnell, Haro and Weiss in regard to Net Base Fuel Cost. I also reviewed Ameren Missouri's response to data requests in this proceeding that relate to the issue. As discussed in Appendix B of this testimony, Brubaker & Associates, Inc. ("BAI") developed a working version of a production cost model database for the Ameren Missouri system using RealTime production cost software of The Emelar Group. The development of this production cost model allowed BAI to use the RealTime production cost software to calculate the estimated impact on Net Fuel Cost from correcting the inputs Ameren Missouri used in its own PROSYM production cost modeling that I identified as being unreasonable. Finally, I applied my experience to the information available in considering the reasonableness of Ameren Missouri's proposed Net Base Fuel Cost amount. As I have noted, I have found issues with a number of Ameren Missouri's production cost input assumptions, Ameren Missouri's failure to consider net bilateral off-system energy sales margins and Ameren Missouri's assumed level of MISO RSG Make Whole Payment Margins.

A. Net Fuel Cost – Production Cost Modeling

Q PLEASE EXPLAIN WHAT PRODUCTION COST MODELING IS AND HOW IT IS BEING USED IN THIS PROCEEDING.

A As Mr. Finnell indicated in his direct testimony, production cost modeling allows the simulation of an electric utility's generation system and load obligations. The costs for fuel, heat rate of generators, hourly market price, generation outage assumptions, hourly loads and many other items are input into the model. The model then performs a commitment and dispatch of generation to meet hourly load obligations. In addition, the model makes use of the hourly market prices and forward contracts that are input into the model to estimate hourly off-system energy purchases and sales. In this proceeding, Ameren Missouri is using production cost modeling to estimate its Net Fuel Cost using normalized loads and market prices.

Q PLEASE DESCRIBE THE REALTIME PRODUCTION COST MODEL AND HOW YOU HAVE USED IT IN THIS PROCEEDING.

A RealTime is a production cost software package similar to the PROSYM production cost software package used by Ameren Missouri. It is a product of The Emelar Group. Both RealTime and PROSYM are competent models for estimating utility production cost. In Case No. ER-2008-0318, it was shown by the Commission Staff and accepted by Ameren Missouri that the RealTime software can produce substantially the same results for Ameren Missouri's Net Fuel Cost as the PROSYM software used by Ameren Missouri's when inputs to both production cost models are similar.

The Commission Staff has been using the RealTime software for over 10 years in respect to electrical corporations over which the Commission has ratemaking jurisdiction. The Commission Staff used the RealTime software in Ameren Missouri's general electric rate proceedings (i.e., Case Nos. ER-2007-0002, ER-2008-0318 and ER-2010-0036) in order to examine the reasonableness of Ameren Missouri's projections of its Net Fuel Cost. I also utilized the RealTime software in Case No. ER-2010-0036 to examine the reasonableness of Ameren Missouri's projections of its Net Fuel Cost.

In this proceeding, I have used the RealTime software to estimate how Ameren Missouri's proposed Net Fuel Cost will change when I correct certain assumptions made by Ameren Missouri that are unreasonable. It is my understanding the Commission Staff is intending to use the RealTime software for a similar purpose in this proceeding.

Q WHAT HAS BEEN DONE IN THIS PROCEEDING TO ENSURE THE REALTIME MODEL PROVIDES RESULTS SIMILAR TO THAT WHICH WOULD BE PROVIDED BY THE PROSYM MODEL?

A BAI, on behalf of MIEC, developed a RealTime model database for this proceeding based on the inputs Ameren Missouri used for its normalized test year Net Fuel Cost PROSYM model runs in this proceeding. This RealTime case, which I will refer to as the "BAI Benchmark Case," projected a Net Fuel Cost within $66,000 (0.014%) of the Net Fuel Cost projected by Ameren Missouri through its PROSYM run for its Net Fuel Cost for the normalized test year in this proceeding. Appendix B to this testimony provides a more detailed discussion on the development of the BAI Benchmark Case and how its estimate of Net Fuel Cost compares to that of Ameren Missouri's PROSYM run for the normalized test year.

Q FROM YOUR REVIEW OF AMEREN MISSOURI'S INPUTS TO ITS PRODUCTION COST MODEL FOR ITS PROPOSED NET FUEL COST, HAVE YOU IDENTIFIED ANY INPUTS THAT YOU FOUND UNREASONABLE?

A Yes. While I continue our review of Ameren Missouri's production cost modeling and will review the direct testimony of other parties concerning that modeling, as of the date of this testimony, I have found three inputs that Ameren Missouri used that I consider to be unreasonable.

Q WHAT ARE THE THREE INPUTS YOU CONSIDER TO BE UNREASONABLE?

A They are as follows:

- The generation capability assumed for the Callaway nuclear generation facility;
- The generation capability assumed for the Sioux coal-fired generation facilities; and
- The generation capability assumed for the Osage hydroelectric generation facility.

<u>A.1. Assumed Generating Capability of Callaway</u>

Q PLEASE EXPLAIN YOUR CONCERN WITH THE GENERATION CAPABILITY THAT AMEREN MISSOURI ASSUMED FOR CALLAWAY.

A In its Net Fuel Cost (i.e., normalized test year) production cost run, Ameren Missouri used monthly generation capabilities for Callaway that are on average 9 MW lower than the values Ameren Missouri used in its calibration production cost run. Ameren Missouri did not identify the change, or a reason for the change, in its direct testimony. In informal discussions with Ameren Missouri's witness Mr. Timothy Finnell, Ameren Missouri indicated the difference was attributable to partial outages because Ameren Missouri did not want to explicitly model partial outages in the normalized test year production cost run. However, our review of Mr. Finnell's workpapers showed that Ameren Missouri has already included the effect of partial outages in the equivalent forced outage rate it used in its normalized test year production cost run. As a result, there is no need to lower Callaway's generation capability by approximately 9 MW on average in the normalized test year production cost run to account for partial outages.

Q PLEASE EXPLAIN HOW YOU KNOW AMEREN MISSOURI ALREADY INCLUDED PARTIAL OUTAGES IN THE FORCED OUTAGE RATE IT USED IN ITS NORMALIZED TEST YEAR PRODUCTION COST RUNS.

A Mr. Finnell's workpaper file "UE Events for EUOR[2] Apr2004 – Mar2010 05-27-10-HC.xlsx" documents the forced outage rate calculations performed by Ameren Missouri. Line 17 of the "Pivot Table" worksheet in that workpaper file shows for Callaway a full unplanned outage rate of *** ***, a partial unplanned outage rate of *** *** and a combined outage rate for both full and partial unplanned outages of *** ***. If Ameren Missouri chose to only use the full unplanned outage rate of *** *** for Callaway, it would be appropriate to reduce Callaway's generation capability in Ameren Missouri's normalized production cost run in order to account for partial unplanned outages. However, Ameren Missouri did not use the full unplanned outage rate of *** *** for Callaway, but instead used the combined outage rate for both full and partial unplanned outages of *** ***.

[2] EUOR is an abbreviation for the term Equivalent Unplanned Outage Rate.

Q PLEASE EXPLAIN HOW YOU KNOW AMEREN MISSOURI USED A COMBINED FULL AND PARTIAL UNPLANNED OUTAGE RATE FOR CALLAWAY RATHER THAN JUST THE FULL UNPLANNED OUTAGE RATE IN AMEREN MISSOURI'S NORMALIZED TEST YEAR PRODUCTION COST RUN.

A The PROSYM input file for Ameren Missouri's direct testimony normalized test year production cost run (MIEC_3-MIEC_3_2-Att-MIEC 3.2 thru Feb 11_uebase_HC.dat) was provided as part of Ameren Missouri's response to Data Request MIEC 3.2. In the generator data for Callaway found in this input file, an equivalent forced outage rate ("EFOR") of *** *** is used instead of Ameren Missouri's full unplanned outage rate of *** ***. Thus, Ameren Missouri has already accounted for partial unplanned outages in its normalized test year production cost run and it should not also be reducing the generation capability of Callaway versus the calibration production cost run in order to account for partial outages.

Q HAVE YOU RERUN YOUR PRODUCTION COST MODEL FOR THE NORMALIZED TEST YEAR USING THE GENERATION CAPABILITY FOR CALLAWAY THAT AMEREN MISSOURI USED IN ITS CALIBRATION PRODUCTION COST MODEL?

A Yes. Our rerun for this adjustment, which is summarized in Schedule JRD-1, reduced Ameren Missouri's proposed Net Fuel Cost by approximately $2.0 million. I recommend that this adjustment be made and that these calibration production cost model capability levels be used for Callaway in production cost runs for the normalized test year in this proceeding.

A.2. Assumed Generating Capability of Sioux Units

Q PLEASE EXPLAIN YOUR CONCERN WITH THE GENERATION CAPABILITY THAT AMEREN MISSOURI ASSUMED FOR THE SIOUX GENERATING UNITS.

A Ameren Missouri has too aggressively lowered the generation capability of the Sioux generating units in its normalized test year production cost run. In the calibration production cost run, each of the two Sioux generating units had monthly generation capabilities of up to *** *** in winter months and up to *** *** in summer months. In its direct testimony normalized test year production cost run, Ameren Missouri modeled each of the Sioux generating units with monthly capabilities of up to *** *** in winter months and up to *** *** in summer months. This amounts to reducing the winter capability of Sioux by 41 MW and the summer capability of Sioux by 24 MW.

Q HAS AMEREN MISSOURI PROVIDED ANY EXPLANATION IN REGARD TO WHY IT LOWERED THE GENERATION CAPABILITY OF THE SIOUX UNITS TO THIS DEGREE IN ITS DIRECT TESTIMONY NORMALIZED TEST YEAR PRODUCTION COST RUN?

A No. While Mr. Finnell in his direct testimony indicates that the net capability of each of the Sioux generating units has been reduced by approximately 12 MW due to the addition of scrubbers at Sioux (Direct Testimony of Finnell at 7), this does not explain a 24 MW to 41 MW drop in the modeled net capability in Ameren Missouri's normalized test year production cost run versus Ameren Missouri's calibration production cost run.

Q WHAT DO YOU RECOMMEND IN REGARD TO THE CAPABILITY TO BE ASSUMED FOR EACH OF THE SIOUX GENERATING UNITS FOR THE NORMALIZED TEST YEAR PRODUCTION COST RUN THAT WILL BE USED TO ESTIMATE AMEREN MISSOURI'S NET FUEL COST?

A I recommend that each of the Sioux generating units be modeled with a June through September capability of *** *** and a December through February capability of *** ***. These levels of capability for each of the Sioux units are 12 MW below the maximum capability modeled during the summer and winter periods in the Ameren Missouri calibration production cost run that models Sioux operation before the addition of the scrubbers at Sioux. This is a level of reduction consistent with the 12 MW decrease in net capability for each of the Sioux generating that is discussed in Mr. Finnell's direct testimony.

Q WHAT GENERATION CAPABILITY DO YOU RECOMMEND FOR EACH OF THE SIOUX UNITS DURING MARCH THROUGH MAY AND OCTOBER THROUGH DECEMBER?

A I recommend using a capability between the summer capability of *** *** and winter capability of *** ***. Specifically, I recommend using the capabilities outlined in Table JRD-1 below.

Table JRD-1

Month	Recommended Capability for Each Sioux Unit
January	*** ***
February	*** ***
March	*** ***
April	*** ***
May	*** ***
June	*** ***
July	*** ***
August	*** ***
September	*** ***
October	*** ***
November	*** ***
December	*** ***

Q HAVE YOU RERUN YOUR PRODUCTION COST MODEL FOR THE NORMALIZED TEST YEAR USING THE GENERATION CAPABILITY NUMBERS FOR EACH OF THE SIOUX UNITS?

A Yes. Our rerun for this adjustment, which is also summarized in Schedule JRD-1, reduced Ameren Missouri's proposed Net Fuel Cost by approximately $4.0 million.

<u>A.3. Assumed Capability of Osage</u>

Q CAN YOU PLEASE EXPLAIN YOUR CONCERN WITH THE GENERATION CAPABILITY ASSUMED FOR THE OSAGE HYDROELECTRIC?

A Yes. In its normalized test year production cost run, Ameren Missouri used a generation capability of *** *** for Osage while in the calibration production cost run Ameren Missouri used a capability of up to *** *** starting in July of 2009 -- the apparent date by which turbine upgrades at Osage had been completed.

Q HAS AMEREN MISSOURI PROVIDED ANY EXPLANATION OF WHY IT LIMITED THE CAPABILITY OF OSAGE TO * *** IN ITS NORMALIZED TEST YEAR PRODUCTION COST RUN?**

A No. Ameren Missouri has provided no explanation.

Q WHAT GENERATION CAPABILITY DO YOU RECOMMEND BE USED FOR OSAGE IN THE NORMALIZED TEST YEAR PRODUCTION COST RUN USED TO ESTIMATE AMEREN MISSOURI'S NET FUEL COST?

A I recommend a capability of *** *** be used for Osage in the normalized test year production cost run. Ameren Missouri has not provided evidence that reasonably justifies using *** *** rather than the *** *** level, which reflects the turbine upgrades that have been completed at Osage.

Q HAVE YOU RERUN YOUR PRODUCTION COST MODEL FOR THE NORMALIZED TEST YEAR USING THE HIGHER * *** CAPABILITY FROM OSAGE THAT YOU HAVE RECOMMENDED?**

A Yes. Our run of this adjustment, which is summarized in Schedule JRD-1, reduced Ameren Missouri's proposed Net Fuel Cost by approximately $0.6 million.

A.4. Summary of Recommended Adjustments to Ameren Missouri's Proposed Level of Net Fuel Cost

Q HAVE YOU CALCULATED THE TOTAL ADJUSTMENT TO AMEREN MISSOURI'S NET FUEL COST THAT WOULD RESULT FROM ALL OF YOUR CORRECTIONS TO AMEREN MISSOURI'S NORMALIZED TEST YEAR PRODUCTION COST RUN INPUTS?

A Yes. The total adjustment would be a $6.6 million reduction to Ameren Missouri's proposed Net Fuel Cost, which would result in the same reduction to Ameren Missouri's Net Base Fuel Cost and revenue requirement. This figure consists of a $2.0 million reduction to correct Ameren Missouri's unreasonable level of assumed Callaway generation capability, a $4.0 million reduction to correct Ameren Missouri's unreasonable level of assumed generation capability for the Sioux units, and a $0.6 million reduction to correct Ameren Missouri's unreasonable level of assumed generation capability for Osage. Further detail on normalized test year production cost reruns we performed for these adjustments is presented on Schedule JRD-1.

B. Other Sales Margins

Q FROM YOUR REVIEW OF AMEREN MISSOURI'S FILING, TESTIMONY, WORKPAPERS AND RESPONSES TO DATA REQUESTS, WHAT ELEMENTS OF AMEREN MISSOURI'S PROPOSED OTHER SALES REVENUE COMPONENT OF NET BASE FUEL COST HAVE YOU FOUND UNREASONABLE?

A While I continue our review of Ameren Missouri's proposed level of Other Sales Revenues and will review the direct testimony of other parties concerning these revenues, as of the date of this testimony, I have found two issues that need to be addressed:

1. Ameren Missouri's failure to include net bilateral off-system energy sales margins in its proposed Other Sales Revenues amount; and

2. The unreasonable level of MISO RSG Make Whole Payment revenues assumed by Ameren Missouri in its proposed Other Sales Revenues amount.

B.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 I am "coining" in this proceeding that 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. 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 Net Base Fuel Cost.

Q HAS AMEREN MISSOURI INCLUDED ANY "BILATERAL OFF-SYSTEM ENERGY SALES MARGINS" IN ITS PROPOSED NET BASE FUEL COST?

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 haul the margins from bilateral energy sales were equal to or less than those made by simply by selling into the MISO day-ahead and real-time energy markets, Ameren Missouri would have likely long ago ceased making bilateral sales of electric energy. Second, when we reviewed Ameren Missouri's monthly 4 CSR 240-3.190(1) F data ("3.190 Data") submittals, which were provided to MIEC for May 2010 through December 2010 pursuant to a non-unanimous stipulation in Case No. ER-2010-0036, we were able to determine that Ameren Missouri over that eight-month period did in fact earn off-system energy sales margins from bilateral sales to third-parties that were greater than that 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 BILATERAL OFF-SYSTEM ENERGY SALES MARGINS FROM BILATERAL SALES IN EXCESS OF THE MARGINS FROM ENERGY SALES INTO THE MISO DAY-AHEAD AND REAL-TIME ENERGY MARKET.

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 simulates 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 Net Base Fuel Cost.

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

A Ameren 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 Locational Marginal Price ("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 May through December of 2010, 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 then algebraically summed these hourly values to get Ameren Missouri's net Bilateral Off-System Energy Sales Margins for this eight-month period. We then also calculated from the 3.190 Data the total day-ahead off-system energy sales revenues earned from MISO by Ameren Missouri during the same eight-month period. We then divided the net Bilateral Off-System Energy Sales Margin amount by the MISO day-ahead off-system energy sales revenues to obtain an estimate of Ameren Missouri's net Bilateral Off-System Energy Sales Margins as a percentage of its MISO day-ahead off-system energy sales revenues. We then multiplied this percentage times the amount of off-system energy sales revenues that result from our normalized test year production cost run (with all of our production cost adjustments included) to calculate a normalized test year level of net Bilateral Off-System Energy Sales Margins. These calculations, which are summarized in Schedule JRD-2, yielded a normalized net Bilateral Off-System Energy Sales Margin of approximately $4.4 million.

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

A I recommend the Commission include approximately $4.4 million of net Bilateral Off-System Energy Sales Margins in the Other Sales Revenues component of

Ameren Missouri's proposed Net Base Fuel Cost. This will reduce Ameren Missouri's Net Base Fuel Cost and revenue requirement by $4.4 million.

Q YOUR CALCULATION IS BASED ON EXAMINING ONLY EIGHT MONTHS OF DATA FOR 2010. IF SIMILAR 3.190 DATA BECAME AVAILABLE IN ORDER TO EXTEND THE CALCULATION TO THE 36 MONTHS ENDING FEBRUARY 28, 2011, WOULD IT BE REASONABLE TO DO SO?

A Yes. The only reason my calculation is based on eight months of data is this is all the 3.190 Data that MIEC has received to date from Ameren Missouri pursuant to the applicable non-unanimous stipulation in Case No. ER-2010-0036.

B.2. MISO Revenue Sufficiency Guarantee ("RSG") Make Whole Payment Margins

Q PLEASE DEFINE AND EXPLAIN THE RELEVANCE OF MISO RSG MAKE WHOLE PAYMENT MARGINS.

A MISO RSG Make Whole Payment Margins are the make whole payment revenues that Ameren Missouri receives under the Midwest Independent Transmission System Operator, Inc.'s ("MISO") revenue sufficiency guarantee provisions less the additional fuel cost Ameren Missouri incurs due to the 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 the MISO's revenue sufficiency guarantee provisions, the MISO guarantees that any generator it commits online will at least earn revenue 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 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.

Neither the RSG Make Whole Payments 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 Make Whole Payments 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 Net Base Fuel Cost.

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

A Yes. Mr. Weiss' workpaper GSW-WP-E185 identifies approximately $4.8 million of MISO RSG Make Whole Payments during the test year for this proceeding. He refers to these payments in this workpaper as RSG and Deviation Revenues.

Q WHAT PORTION OF THIS $4.8 MILLION AMOUNT HAS AMEREN MISSOURI INCLUDED IN ITS PROPOSED OTHER SALES MARGINS TOTAL AS MISO RSG MAKE WHOLE PAYMENT MARGINS?

A None. In Mr. Weiss' workpaper GSW-WP-E185, Ameren Missouri assumes 0% of its RSG Make Whole Payment revenues are margins. In other words, Ameren Missouri assumes the MISO RSG Make Whole Payments it received equals the out-of-merit order fuel costs it incurred.

Q HAS AMEREN MISSOURI PROVIDED TESTIMONY SUPPORTING THIS ASSUMPTION?

A No. Unlike in his direct testimony in Case No. ER-2010-0036, Ameren Missouri witness Haro is conspicuously silent in regard to the subject of RSG Make Whole Payment Margins in his direct testimony in this proceeding. Furthermore, when Ameren Missouri was asked in discovery to provide details or summary calculations supporting its assumption in this proceeding, Ameren Missouri simply responded that since the true-up in Case No. ER-2010-0036 resulted in no net RSG Make Whole Payment Margins, Ameren Missouri assumed that there are no RSG Make Whole Payment Margins for this case (Ameren Missouri's response to Data Request MPSC 0250 attached as Schedule JRD-3).

Q IS AMEREN MISSOURI'S ASSUMPTION THAT IT EARNED NO MISO RSG MAKE WHOLE PAYMENT MARGINS REASONABLE?

A No. In its direct testimony in Case No. ER-2010-0036, Ameren Missouri counted 39% of its MISO RSG Make Whole Payment revenues as MISO RSG Make Whole Payment Margins and included that amount in the Other Sales Revenues component of its proposed Net Base Fuel Cost (Ameren Missouri's response to Data Request MIEC 1-12 in Case No. ER-2010-0036 attached as Schedule JRD-4). Ameren Missouri has not presented evidence in its direct testimony in this proceeding supporting its assumption that 0% (i.e., none) of its MISO RSG Make Whole Payments are margins.

Q WHAT DO YOU RECOMMEND TO THE COMMISSION REGARDING THE MISO RSG MAKE WHOLE PAYMENT MARGINS ISSUE?

A I recommend that, unless reasonable evidence is presented that shows the MISO RSG Make Whole Payment Margins should be a different amount, Ameren Missouri's MISO RSG Make Whole Payment Margins be assumed to be equal to 39% of Ameren Missouri's test year receipt of MISO RSG Make Whole Payment revenues. As shown in Schedule JRD-5, this amounts to approximately $1.9 million. As I have noted, 39% is the percentage of MISO RSG Make Whole Payment revenues that Ameren Missouri used in its direct testimony in Case No. ER-2010-0036 for its MISO RSG Make Whole Payment Margins amount.

Q IF, DURING THE TRUE-UP PORTION OF THIS PROCEEDING, AMEREN MISSOURI'S MISO RSG MAKE WHOLE PAYMENT REVENUES ARE ADJUSTED TO THE ACTUAL ANNUAL AVERAGE AMOUNT FOR THE 36 MONTHS ENDING FEBRUARY 28, 2011, SHOULD THE 39% VALUE BE APPLIED TO THE TRUE-UP LEVEL OF THOSE PAYMENTS IN ORDER TO DETERMINE AMEREN MISSOURI'S MISO RSG MAKE WHOLE PAYMENT MARGINS?

A Yes, unless reasonable evidence is presented before then demonstrating a different percentage should be used.

B.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 TO AMEREN MISSOURI'S PROPOSED LEVEL OF OTHER SALES REVENUES?

A Yes. My total adjustment would be a $6.3 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 Net Base Fuel Cost and Revenue Requirement. This consists of a $4.4 million increase in Other Sales Revenues to account for Ameren Missouri's net level of Bilateral Off-System Energy Sales Margins and a $1.9 million increase in Other Sales Revenues to account for Ameren Missouri's MISO RSG Make Whole Payment Margins.

III. TRANSMISSION REVENUES

Q HAVE YOU RECOMMENDED ADJUSTMENTS TO THE TRANSMISSION REVENUES COMPONENT OF AMEREN MISSOURI'S PROPOSED REVENUE REQUIREMENT?

A Yes. I am recommending the Ameren Missouri's proposed level of transmission revenues be increased by $2.9 million, which will lower Ameren Missouri's proposed revenue requirement by the same amount.

Q PLEASE EXPLAIN YOUR RECOMMENDED ADJUSTMENT TO THE TRANSMISSION REVENUES COMPONENT OF AMEREN MISSOURI'S PROPOSED REVENUE REQUIREMENT.

A Transmission revenues are a component of Ameren Missouri's Other Electric Revenues found in Mr. Weiss' Schedule GSW-E10. Mr. Weiss' workpaper GSW-WP-E191 shows that for the test year, Ameren Missouri had approximately $15.0 million in transmission revenues. Mr. Weiss' workpaper GSW-WP-E192 shows this consisted of approximately $0.8 million in Schedule 1 (Scheduling Service) revenues, $1.5 million in Schedule 2 (Reactive Supply Service) revenues, $9.0 million in Schedule 7 and 8 (collectively, Point-to-Point Service) revenues and $3.7 million in Schedule 9 (Network Transmission Service) revenues. As discussed on page 17 of

Mr. Weiss' direct testimony, shown on his Schedule GSW-E10 and on his workpapers GSW-WP-E191 through GSW-WP-E194, Ameren Missouri is only proposing one pro forma adjustment to the test year transmission revenues in the amount of an approximately $9.1 million increase of those revenues to reflect an increase in its Schedule 2 (Reactive Supply Service) rate less settlement payments that were agreed to by Ameren Missouri in order to gain acceptance of that rate increase by the Federal Energy Regulatory Commission ("FERC").

While I agree with Ameren Missouri's pro forma adjustment of its Schedule 2 revenues, that adjustment is not the only pro forma adjustment that should be made to Ameren Missouri's transmission revenues.

Q WHAT IS THE OTHER PRO FORMA ADJUSTMENT TO AMEREN MISSOURI'S TRANSMISSION REVENUES THAT SHOULD BE MADE?

A An upward pro forma adjustment should be made to Ameren Missouri's test year Schedule 7 and 8 (Point-to-Point Service) revenues and Schedule 9 (Network Transmission Service) revenues to reflect Ameren Missouri's FERC transmission rate that will be in effect at the end of the true-up period versus the transmission rates that were in effect during the test year period. Failure to do so would be inconsistent with Ameren Missouri's proposal to include plant additions through the end of the true-up period in rate base. It is important that the FERC transmission rate assumed in effect for establishing Ameren Missouri's retail electric rates, and resulting transmission revenues, as closely as reasonably possible be based on the rate base assumed for those retail rates. This can be achieved by making a pro forma adjustment to Ameren Missouri's test year Schedule 7, 8 and 9 revenues to reflect the Ameren Missouri's FERC transmission rate that is in effect at the end of the true-up period.

Q HOW HAS AMEREN MISSOURI'S FERC TRANSMISSION RATE CHANGED FROM THE BEGINNING OF THE TEST YEAR TO THE END OF THE TRUE-UP PERIOD?

A Ameren Missouri's FERC transmission rate <u>increased by approximately 41%</u> over that period. For the first two months of the test year, Ameren Missouri's FERC transmission rate was $725.414 per MW-month. For the remaining 10 months of the test year, Ameren Missouri's FERC transmission rate was $861.143 per MW-month. Since June 1, 2010, Ameren Missouri's FERC transmission rate has been $1,020.952 per MW-month. This latter rate will still be in effect at the end of the true-up period. However, it should also be noted that Ameren Missouri's FERC transmission rate will likely increase again on June 1, 2011 because Ameren Missouri's transmission rate base and expenses continue to grow and Ameren Missouri can automatically reflect these increases through its FERC formula transmission rate on an annual basis.

Q PLEASE EXPLAIN YOUR SPECIFIC RECOMMENDED ADJUSTMENT TO AMEREN MISSOURI'S TRANSMISSION REVENUES.

A I recommend that Ameren Missouri's Schedule 7, 8 and 9 revenues for the first two months of the test year be scaled up by the ratio of Ameren Missouri's current FERC transmission rate to that in effect during the first two months of the test year. In addition, Ameren Missouri's test year Schedule 7, 8 and 9 revenues for the remaining 10 months of the test year be scaled up by the ratio of Ameren Missouri's current FERC transmission rate to that in effect during the latter 10 months of the test year. I have calculated this adjustment in my Schedule JRD-6. It totals to approximately $2.9 million.

Q WOULD A REASONABLE ALTERNATIVE TO YOUR ADJUSTMENT BE TO USE ACTUAL TRANSMISSION REVENUES COLLECTED DURING THE 12 MONTHS THAT CONCLUDE AT THE END OF THE TRUE-UP PERIOD?

A It would be provided that the actual Schedule 7, 8 and 9 transmission revenues collected during March through May of 2010 are scaled up by the ratio of the current transmission rate ($1,020.952 per MW-month) to the transmission rate that was in effect during those three months ($861.143 per MW-month). An adjustment would not be needed for June 2010 through February 2011 because the current transmission rate was in effect over that period.

IV. RATEMAKING TREATMENT OF WHOLESALE SALES TO CERTAIN MUNICIPALS

Q IS AMEREN MISSOURI PROPOSING A DIFFERENT RATEMAKING TREATMENT OF WHOLESALE SALES OF ELECTRIC POWER TO CERTAIN MUNICIPAL ELECTRIC UTILITIES?

A Yes. In previous proceedings, Ameren Missouri calculated its total revenue requirement to serve the combination of its sales to its retail customers and its multi-year wholesale sales of electricity to certain municipal electric utilities. Ameren Missouri utilized a jurisdictional allocator to allocate that revenue requirement between its Missouri retail customers and the municipal electric utility customers. In this proceeding, Ameren Missouri has not included those wholesale sales to certain municipal electric systems in determining its revenue requirement and instead assumed those wholesale sales are implicitly part of its estimated normalized test year off-system capacity and energy sales. The result is a revenue requirement that is entirely allocated to Ameren Missouri's retail customers.

Q IS MIEC TAKING ISSUE WITH THIS PROPOSED RATEMAKING TREATMENT IN THIS PROCEEDING?

A MIEC is not taking issue with this proposed ratemaking treatment in this proceeding. However, MIEC reserves the right to challenge such ratemaking treatment of wholesale sales in future rate proceedings.

V. CONCLUSIONS AND RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A I recommend that the Commission reduce Ameren Missouri's proposed Net Base Fuel Cost (and, thus, its proposed revenue requirement) by not less than $12.9 million to correct: (i) the unreasonable level of generation capability assumed by Ameren Missouri for the Callaway, Osage and Sioux generation facilities in its normalized test year production cost modeling; (ii) the failure by Ameren Missouri to include an estimate of its bilateral off-system energy sales margins; and (iii) the unreasonable level of MISO RSG Make Whole Payment Margins proposed by Ameren Missouri.

In addition, I recommend that the transmission revenues included as a credit in Ameren Missouri's proposed revenue requirement be adjusted to reflect Ameren Missouri's current FERC-authorized wholesale transmission rates in order to be consistent with Ameren Missouri's inclusion in rate base of all plant in-service by the end of the true-up period. I have estimated this adjustment will raise Ameren Missouri's proposed transmission revenues by $2.9 million, which will in turn lower Ameren Missouri's proposed revenue requirement by the same amount.

In total, I am recommending Ameren Missouri's proposed revenue requirement be lowered by $15.8 million.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

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

Utilities' transmission system to support planning and operating decisions. This involved the use of load flow and power system stability computer simulations. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1997 I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

In addition to my technical responsibilities, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order

No. 889. During this time I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000, Montana Power Company, Docket No. ER98-2382-000, Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003, SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000, Alliance Companies, et al., Docket No. EL02-65-000, et al., Entergy Services, Inc., Docket No. ER01-2201-000, and Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Docket No. RM01-12-000. I have also filed or presented testimony before the Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the

Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, fuel adjustment clauses, interruptible rates, market power, market structure, prudency, resource planning, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

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

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

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

Appendix B

Benchmarking RealTime to the
<u>Ameren Missouri PROSYM Production Cost Model</u>

Q PLEASE EXPLAIN HOW BAI DEVELOPED ITS "BAI BENCHMARK CASE" THAT WAS USED TO COMPARE THE RESULTS OF THE EMELAR GROUP REALTIME PRODUCTION COST SIMULATION MODEL TO THE RESULTS OF THE PROSYM PRODUCTION COST SIMULATION MODEL.

A We started with the Staff's true-up production cost model database for RealTime that was developed by the Commission Staff in Case No. ER-2010-0036. We then modified the inputs to that database to as closely as possible, within the bounds of the capability of the RealTime program, match the inputs Ameren Missouri used in its direct testimony normalized test year PROSYM run based on our review of the workpapers of Mr. Finnell, workpapers of Mr. Haro and Ameren Missouri's responses to data requests in this proceeding.

Q CAN YOU PLEASE DETAIL HOW THE RESULTS OF THE BAI BENCHMARK CASE COMPARE TO THAT OF THE DIRECT TESTIMONY NORMALIZED TEST YEAR PROSYM PRODUCTION COST MODEL RUN PERFORM BY AMEREN MISSOURI?

A Yes. As detailed in Schedule JRD-1, the results of the BAI Benchmark Case yielded a Net Fuel Cost of $464.944 million versus the $464.879 million Net Fuel Cost yielded from the Ameren Missouri normalized test year PROSYM production cost simulation model run. Thus, in aggregate, the BAI Benchmark Case results are within approximately $66,000 or 0.014% of the Ameren Missouri normalized test year PROSYM run. In addition, as also detailed in Schedule JRD-7, the annual MWh of energy production at each of Ameren Missouri's nuclear, coal and hydroelectric stations in the BAI Benchmark Case is within ±1% of the level they are at in Ameren Missouri's normalized test year PROSYM run. Furthermore, Ameren Missouri's annual off-system energy sales and purchase MWh in the BAI Benchmark Case are each with ±1.5% of the level they are at in Ameren Missouri's normalized test year PROSYM run. The only difference of significance between the BAI Benchmark Case and Ameren Missouri normalized test year PROSYM run is in regard to combustion turbine generation. The BAI Benchmark Case has *** ***, or approximately 76% more combustion turbine energy production than the Ameren Missouri normalized test year PROSYM run. However, this difference does not have a significant impact on predicting Net Fuel Cost since Net Fuel Cost in aggregate is within 0.014%; individual nuclear, coal and hydroelectric station MWh production are all within ±1%; and off-system energy sales and purchases are each within ±1.5%.

Q HAVE YOU ALSO BENCHMARKED THE REALTIME MODEL AGAINST AMEREN MISSOURI'S CALIBRATION PROSYSM RUN?

A Yes. I will refer to this as the "BAI Calibration Case." For the BAI Calibration Case, we modified the BAI Benchmark Case to use the inputs used by Ameren Missouri for its calibration PROSYM run. In the BAI calibration case, the annual energy production for Ameren Missouri's nuclear, coal and hydroelectric generation was within ±0.5% of the Ameren Missouri calibration PROSYM run and within ±1.0% of Ameren Missouri's actual calendar year 2009 nuclear, coal and hydroelectric energy production. Off-system energy sales in the BAI Calibration Case were within ±1.0% of the Ameren Missouri calibration PROSYM run and ±0.5% of Ameren Missouri's actual MWh of off-system energy sales for calendar year 2009. Only in purchases and combustion turbine generation MWh was there a significant difference between the BAI and Ameren Missouri calibration runs. BAI had approximately 300,000 (12%) more MWh of purchases and 81,796 (54%) more MWh of combustion turbine generation energy production than Ameren Missouri. However, BAI calibration case MWh for these two categories were closer to Ameren Missouri's actual calendar year 2009 amounts than Ameren Missouri's calibration run. Schedule JRD-8 provides more detail on these comparisons.

Q WHAT DO YOU CONCLUDE REGARDING THE BENCHMARKING ANALYSIS OF REALTIME PERFORMED BY BAI UNDER YOUR DIRECTION AND SUPERVISION?

A When utilizing the same inputs as Ameren Missouri, the RealTime program provides Net Fuel Cost results nearly identical to that of the PROSYM program used by Ameren Missouri. As such, RealTime can be reasonably utilized to calculate the impact that changes to the input assumptions used by Ameren Missouri will have on Ameren Missouri's Net Fuel Cost.

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Non-Proprietary
Schedule JRD-1
Production Cost Modeling (Net Fuel Cost) Adjustments Proposed by MIEC

	Increase/ (Decrease) vs. BAI Benchmark Case	Net Fuel Cost	Gross Fuel Cost	OSS Revenues	Coal Fuel Cost	Nuclear Fuel Cost	Oil/Gas Fuel Cost	Spot Purchased Power	Wind Purchased Power
Ameren Missouri ProSym Case-in-Chief	$ (65,576)	$ 464,878,678	$ 839,215,678	$ 374,337,000					
BAI Benchmark Case	$ -	$ 464,944,254	$ 844,434,656	$ 379,490,402					
BAI Callaway Capability Adjustment	$ (1,983,775)	$ 462,960,479	$ 844,800,505	$ 381,840,026					
BAI Sioux Capability Adjustment	$ (4,010,339)	$ 460,933,915	$ 848,362,222	$ 387,428,307					
BAI Osage Capability Adjustment	$ (613,615)	$ 464,330,639	$ 844,375,676	$ 380,045,037					
BAI Callaway Capability Adj	$ (1,983,775)	$ 462,960,479	$ 844,800,505	$ 381,840,026					
BAI Callaway and Sioux Capabilities Adj	$ (5,940,124)	$ 459,004,130	$ 848,375,413	$ 389,371,283					
BAI Callaway, Sioux and Osage Capabilities Adj	$ (6,560,709)	$ 458,383,545	$ 848,345,980	$ 389,962,435					

	Net MWhrs	Gross MWhrs	Native Load MWhrs	OSS MWhrs	Coal MWhrs	Nuclear MWhrs	Oil/Gas MWhrs	Pumped Storage MWhrs	Hydro MWhrs	Spot Purchased Power MWhrs	Wind Purchased Power MWhrs
Ameren Missouri ProSym Case-in-Chief											
BAI Benchmark Case											
BAI Callaway Capability Adjustment											
BAI Sioux Capability Adjustment											
BAI Osage Capability Adjustment											
BAI Callaway Capability Adj											
BAI Callaway and Sioux Capabilities Adj											
BAI Callaway, Sioux and Osage Capabilities Adj											

Notes

Gross MWhrs is a Summation of all Coal, Nuclear, Gas, Oil, Hydro, and Purchased Power MWhrs (both Spot Purchases and Wind)
Net MWhrs is the Difference of Gross MWhrs and Off-System Sales MWhrs
Native Load MWhrs is the Summation of Net MWhrs and Pumped Storage MWhrs
Nuclear Fuel Cost Includes Spent Fuel Charge

Non-Proprietary

Ameren Missouri
Case No. ER-2011-0028
Schedule JRD-2
MIEC Adjustments to Off-System Sales Revenues - Bilateral Sales

Line No.	Description	Amount	Source Document
1	May 2010 - Dec 2010 MISO Day Ahead Off System Energy Sales Revenues		MPSC 3.910 Data May - Dec 2010
2	May 2010 - Dec 2010 Bilateral Energy Sales Margins		MPSC 3.910 Data May - Dec 2010
3	Bilateral Energy Sales Margins as a Percentage of MISO Day-Ahead OSS	1.1385%	Line 2 / Line 1
4	OSS Revenues from BAI Adjusted RealTime Production Cost Run	$ 389,962,435	Schedule JRD-1
5	Estimated Normalized Test Year Bilateral Off-System Energy Sales Margins	$ 4,439,710	Line 3 x Line 4

Ameren Missouri
Response to MPSC Staff Data Request
MPSC Case No. ER-2011-0028
In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area

Data Request No.: MPSC 0250 – Kofi Boateng

Regarding MISO Day 2 Revenues (GSW-WP-E185), please provide details or summary of your calculations that showed that there are no margins embedded in the RSG make whole payments.

RESPONSE

Prepared By: Mark J. Peters
Title: Managing Supervisor
Date: 12/15/2010

Consistent with its treatment of this matter in the prior case, Ameren Missouri’s revenue requirement in its initial filing in this case utilized the results of the true-up period calculation (which was zero) from the prior case (Case No. ER-2010-0036) for this factor. Since the true-up calculation was zero, there are no margins embedded in the make-whole payments.

AmerenUE
Response to MIEC Data Request
MPSC Case No. ER-2010-0036
Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area

Data Request No.: MIEC 1-12Diana Vuylsteke

Please refer to Mr. Haro's direct testimony at pages 15-16. Please provide all documents in the Company's possession as well as all calculations that support the RSG MWP revenue of $2.4 million.

RESPONSE

Prepared By: Jaime Haro
Title: Director, Asset Mgmt & Trading
Date: 9/29/09

Please note that, as detailed in my testimony, the figure of $2.4 million referenced above represents the margin contained within the RSG MWP and is not, nor was it represented as, the RSG MWP revenue.

This amount was calculated by taking the Actual 12 months ended March 31,2009 RSG and Deviation Revenues, as recorded in Account 447, of $6,066,928, and multiplying by 39%, which was the percentage of margin within the RSG MWP calculated in the prior docket for this factor. This calculation can be found in the work papers of Gary Weiss, file name: 7-UEC MISO Day 2 Rev Exp 12 months 3-31-09.

As with other components of total off-system sales, AmerenUE expects to true-up this calculation and the resulting values as of January 31, 2010.

Ameren Missouri
Case No. ER-2011-0028

Schedule JRD-5

MISO RSG Make Whole Payment Margins Adjustment Proposed by MIEC

Line	Description	Amount	Notes
1	April 2009 - March 2010 MISO RSG Make Whole Payment Revenues	$4,791,738	Weiss Direct Testimony Workpaper GSW-WP-E185
2	Estimated Margin Percentage of MISO RSG Make Whole Payment Revenues	39%	Ameren Missouri's Response to Data Request MIEC 1-12 in Case No. ER-2010-0036
3	Ameren Missouri's Direct Testimony Estimate of April 2009 - March 2010 MISO RSG Make Whole Payment Margins	$0	Weiss Direct Testimony Workpaper GSW-WP-E185
4	MIEC's Estimate of April 2009 - March 2010 MISO RSG Make Whole Payment Margins	$1,868,778	Line 1 x Line 2
5	MIEC's Recommended MISO RSG Make Whole Payment Margins Adjustment	$1,868,778	Line 4 - Line 3

Ameren Missouri
Case No. ER-2011-0028

Schedule JRD-6

Transmission Revenue Adjustment Proposed by MIEC

		2009									**2010**			
Line	**Description**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**	**TOTALS**
1	Schedule 7 & 8 Revenues (Basic Transmission Revenues)[1]	$594,419	$602,239	$581,190	$770,212	$811,987	$665,172	$887,951	$669,196	$845,922	$1,041,745	$766,783	$738,798	$8,975,614
2	Schedule 9 (Network Transmission Service) Revenues[2]	$213,297	$232,641	$351,428	$343,194	$360,231	$318,510	$257,123	$250,304	$369,695	$384,648	$314,347	$300,647	$3,696,065
3	Total Schedule 7, 8 and 9 Revenue	$807,716	$834,880	$932,618	$1,113,406	$1,172,218	$983,682	$1,145,074	$919,500	$1,215,617	$1,426,393	$1,081,130	$1,039,445	$12,671,679
4	Schedule 7, 8 and 9 Transmision Rate (per MW-month)[3]	$725.414	$725.414	$725.414	$861.143	$861.143	$861.143	$861.143	$861.143	$861.143	$861.143	$861.143	$861.143	
5	Schedule 7, 8 and 9 Rate at End of True-Up Period (per MW-month)[4]	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	$1,020.952	
6	Estimated Pro Forma Adjustment Factor[5]	1.407	1.407	1.407	1.186	1.186	1.186	1.186	1.186	1.186	1.186	1.186	1.186	
7	Estimated Pro Forma Schedule 7, 8 and 9 Revenue Adjustment[6]	$329,068	$340,135	$379,954	$206,623	$217,538	$182,550	$212,500	$170,639	$225,591	$264,707	$200,634	$192,898	$2,922,837

Notes:
1. Ameren Missouri Workpaper GSW-WP-E192
2. Ameren Missouri Workpaper GSW-WP-E192
3. Midwest ISO OASIS
4. Midwest ISO OASIS
5. Line 5 / Line 4
6. Line 3 * (Line 6 - 1)

Non-Proprietary

Schedule JRD-7

Comparison of BAI Benchmark Case to Ameren Missouri Normalized Test Year Production Cost Run

All Numbers are in MWh

		April	May	June	July	August	September	October	November	December	January	February	March	Total	Percent Difference BAI vs. ProSym
Callaway	ProSym														-0.19%
	BAI														
	ProSym-BAI														
Rush	ProSym														-0.82%
	BAI														
	ProSym-BAI														
Labadie	ProSym														0.79%
	BAI														
	ProSym-BAI														
Sioux	ProSym														0.45%
	BAI														
	ProSym-BAI														
Meramec	ProSym														0.14%
	BAI														
	ProSym-BAI														
Osage	ProSym														-0.24%
	BAI														
	ProSym-BAI														
Keokuk	ProSym														-0.05%
	BAI														
	ProSym-BAI														
CTG	ProSym														75.57%
	BAI														
	ProSym-BAI														
Purchases	ProSym														-0.75%
	BAI														
	ProSym-BAI														
Sales	ProSym														1.07%
	BAI														
	ProSym-BAI														
Net	ProSym														0.08%
	BAI														
	ProSym-BAI														
Coal	ProSym														0.29%
	BAI														
	ProSym-BAI														
Hydro	ProSym														-0.13%
	BAI														
	ProSym-BAI														
Ameren Gen	ProSym														0.31%
	BAI														
	ProSym-BAI														

Schedule JRD-8

Comparison of BAI Calibration Case to Ameren Missouri Calibration Production Cost Run and Actual Calendar Year 2009 Energy Production

All Numbers are in MWh

		January	February	March	April	May	June	July	August	September	October	November	December	Total	Percent Difference	
Callaway	Actual 2009	928,441	535,798	826,689	796,254	909,950	836,422	898,752	899,588	878,322	918,753	891,471	926,676	10,247,116		
	BAI	928,512	544,679	815,194	788,482	909,634	844,145	898,752	899,496	878,400	918,470	889,834	926,678	10,242,276	BAI vs. Actual	-0.05%
	ProSym	928,500	537,000	829,100	796,200	907,200	860,400	892,600	896,900	877,100	918,800	889,900	927,000	10,260,700	ProSym vs. Actual	0.13%
	Actual-BAI	-71	-8,881	11,495	7,772	316	-7,723	0	92	-78	283	1,637	-2	4,840	BAI vs. ProSym	-0.18%
Rush	Actual 2009	835,596	673,628	709,270	517,483	610,329	693,066	667,548	718,634	575,123	701,512	627,639	687,360	8,017,188		
	BAI	816,391	677,531	695,523	501,243	636,115	702,300	680,443	701,466	569,289	665,007	642,269	745,078	8,032,655	BAI vs. Actual	0.19%
	ProSym	810,000	672,500	709,000	505,000	638,700	708,200	681,100	718,000	587,200	714,700	651,500	744,400	8,140,300	ProSym vs. Actual	1.54%
	Actual-BAI	19,205	-3,903	13,747	16,240	-25,786	-9,234	-12,895	17,168	5,834	36,505	-14,630	-57,718	-15,467	BAI vs. ProSym	-1.32%
Labadie	Actual 2009	1,556,114	1,329,232	1,476,669	1,247,746	1,031,185	1,416,851	1,584,042	1,539,861	1,397,061	1,535,770	1,554,353	1,568,684	17,237,568		
	BAI	1,607,624	1,379,673	1,525,954	1,257,848	1,017,895	1,411,569	1,552,397	1,516,515	1,370,984	1,529,765	1,534,951	1,565,163	17,270,338	BAI vs. Actual	0.19%
	ProSym	1,595,100	1,385,600	1,526,100	1,272,900	1,020,300	1,425,200	1,580,000	1,559,300	1,392,200	1,531,200	1,557,300	1,564,500	17,409,700	ProSym vs. Actual	1.00%
	Actual-BAI	-51,510	-50,441	-49,285	-10,102	13,290	5,282	31,645	23,346	26,077	6,005	19,402	3,521	-32,770	BAI vs. ProSym	-0.80%
Sioux	Actual 2009	599,864	535,985	481,676	466,559	414,645	509,429	399,499	521,073	473,220	454,147	325,868	578,542	5,760,507		
	BAI	607,926	552,977	508,629	485,206	443,376	542,714	413,659	527,172	492,784	447,990	345,108	580,642	5,948,183	BAI vs. Actual	3.26%
	ProSym	603,000	538,200	470,800	471,800	437,400	540,500	422,600	526,900	492,000	453,700	346,200	584,800	5,887,900	ProSym vs. Actual	2.21%
	Actual-BAI	-8,062	-16,992	-26,953	-18,647	-28,731	-33,285	-14,160	-6,099	-19,564	6,157	-19,240	-2,100	-187,676	BAI vs. ProSym	1.02%
Meramec	Actual 2009	496,313	510,079	459,013	497,469	521,632	439,334	462,901	441,442	445,492	399,009	252,980	436,846	5,362,510		
	BAI	476,820	513,494	466,770	492,946	524,616	448,871	473,903	443,036	446,701	393,296	255,675	439,043	5,375,171	BAI vs. Actual	0.24%
	ProSym	462,600	493,300	443,600	483,800	515,100	441,400	464,600	438,300	448,800	401,000	262,900	428,200	5,283,600	ProSym vs. Actual	-1.47%
	Actual-BAI	19,493	-3,415	-7,757	4,523	-2,984	-9,537	-11,002	-1,594	-1,209	5,713	-2,695	-2,197	-12,661	BAI vs. ProSym	1.73%
Osage	Actual 2009	46,546	37,981	49,431	124,547	157,978	148,238	46,880	14,181	27,925	129,370	134,730	39,532	957,339		
	BAI	46,488	37,988	49,634	124,376	158,183	148,154	46,731	14,241	27,538	129,555	134,533	39,532	956,953	BAI vs. Actual	-0.04%
	ProSym	47,800	36,400	54,700	121,200	156,400	145,400	50,400	13,500	36,500	122,000	129,400	43,600	957,300	ProSym vs. Actual	0.00%
	Actual-BAI	58	-7	-203	171	-205	84	149	-60	387	-185	197	0	386	BAI vs. ProSym	-0.04%
Keokuk	Actual 2009	72,840	70,047	69,675	72,492	70,469	76,332	94,140	90,132	70,719	87,062	88,243	87,749	949,900		
	BAI	72,840	70,047	69,759	72,481	70,502	76,329	94,141	90,129	70,673	87,086	88,154	87,749	949,890	BAI vs. Actual	0.00%
	ProSym	73,900	68,200	71,000	72,300	70,100	76,600	94,300	89,400	71,900	86,500	87,600	88,000	949,800	ProSym vs. Actual	-0.01%
	Actual-BAI	0	0	-84	11	-33	3	-1	3	46	-24	89	0	10	BAI vs. ProSym	0.01%
CTG	Actual 2009	8,552	11,275	10,525	4,540	14,624	72,379	13,086	48,955	8,943	18,785	8,012	11,112	230,788		
	BAI	121,875	10,290	0	186	0	15,807	0	834	0	0	0	0	148,992	BAI vs. Actual	-35.44%
	ProSym	65,300	6,500	400	400	0	17,600	0	6,600	0	0	0	0	96,800	ProSym vs. Actual	-58.06%
	Actual-BAI	-113,323	985	10,525	4,354	14,624	56,572	13,086	48,121	8,943	18,785	8,012	11,112	81,796	BAI vs. ProSym	53.92%
Purchases	Actual 2009	156,719	114,530	109,737	150,204	296,833	132,070	199,731	175,205	123,718	135,698	102,416	171,105	1,867,966		
	BAI	163,130	144,011	176,871	182,646	164,830	246,343	138,788	173,607	31,750	28,317	29,857	80,753	1,560,903	BAI vs. Actual	-16.44%
	ProSym	150,600	128,900	148,000	165,400	147,300	185,200	99,600	128,900	52,100	47,100	48,500	91,800	1,393,400	ProSym vs. Actual	-25.41%
	Actual-BAI	-6,411	-29,481	-67,134	-32,442	132,003	-114,273	60,943	1,598	91,968	107,381	72,559	90,352	307,063	BAI vs. ProSym	12.02%
Sales	Actual 2009	963,294	992,950	1,293,995	1,162,522	1,119,903	768,563	885,619	833,907	998,048	1,547,846	1,123,233	757,337	12,447,217		
	BAI	1,100,657	1,080,581	1,461,178	1,212,339	1,038,614	859,630	822,240	772,377	898,326	1,344,223	1,077,251	723,184	12,390,600	BAI vs. Actual	-0.45%
	ProSym	995,700	1,016,500	1,405,400	1,196,000	1,006,100	823,800	808,600	783,900	968,100	1,419,900	1,130,200	730,700	12,284,900	ProSym vs. Actual	-1.30%
	Actual-BAI	-137,363	-87,631	-167,183	-49,817	81,289	-91,067	63,379	61,530	99,722	203,623	45,982	34,153	56,617	BAI vs. ProSym	0.86%
Net	Actual 2009	3,737,691	2,825,605	2,898,690	2,714,772	2,907,742	3,555,558	3,480,960	3,615,164	3,002,475	2,832,260	2,862,479	3,750,269	38,183,665		
	BAI	3,740,949	2,850,109	2,847,156	2,693,075	2,886,537	3,576,602	3,476,574	3,594,119	2,989,793	2,855,263	2,843,130	3,741,454	38,094,761	BAI vs. Actual	-0.23%
	ProSym	3,741,100	2,850,100	2,847,300	2,693,000	2,886,400	3,576,700	3,476,600	3,593,900	2,989,700	2,855,100	2,843,100	3,741,600	38,094,600	ProSym vs. Actual	-0.23%
	Actual-BAI	-3,258	-24,504	51,534	21,697	21,205	-21,044	4,386	21,045	12,682	-23,003	19,349	8,815	88,904	BAI vs. ProSym	0.00%
Coal	Actual 2009	3,487,887	3,048,924	3,126,628	2,729,257	2,577,791	3,058,680	3,113,990	3,221,010	2,890,896	3,090,438	2,760,840	3,271,432	36,377,773		
	BAI	3,508,761	3,123,675	3,196,876	2,737,243	2,622,002	3,105,454	3,120,402	3,188,189	2,879,758	3,036,058	2,778,003	3,329,926	36,626,347	BAI vs. Actual	0.68%
	ProSym	3,470,700	3,089,600	3,149,500	2,733,500	2,611,500	3,115,300	3,148,300	3,242,500	2,920,200	3,100,600	2,817,900	3,321,900	36,721,500	ProSym vs. Actual	0.94%
	Actual-BAI	-20,874	-74,751	-70,248	-7,986	-44,211	-46,774	-6,412	32,821	11,138	54,380	-17,163	-58,494	-248,574	BAI vs. ProSym	-0.26%
Hydro	Actual 2009	119,386	108,028	119,106	197,039	228,447	224,570	141,020	104,313	98,644	216,432	222,973	127,281	1,907,239		
	BAI	119,328	108,035	119,393	196,857	228,685	224,483	140,872	104,370	98,211	216,641	222,687	127,281	1,906,843	BAI vs. Actual	-0.02%
	ProSym	121,700	104,600	125,700	193,500	226,500	222,000	144,700	102,900	108,400	208,500	217,000	131,600	1,907,100	ProSym vs. Actual	-0.01%
	Actual-BAI	58	-7	-287	182	-238	87	148	-57	433	-209	286	0	396	BAI vs. ProSym	-0.01%
Ameren Gen	Actual 2009	4,544,266	3,704,025	4,082,948	3,727,090	3,730,812	4,192,051	4,166,848	4,273,866	3,876,805	4,244,408	3,883,296	4,336,501	48,762,916		
	BAI	4,678,476	3,786,679	4,131,463	3,722,768	3,760,321	4,189,889	4,160,026	4,192,889	3,856,369	4,171,169	3,890,524	4,383,885	48,924,458	BAI vs. Actual	0.33%
	ProSym	4,586,200	3,737,700	4,104,700	3,723,600	3,745,200	4,215,300	4,185,600	4,248,900	3,905,700	4,227,900	3,924,800	4,380,500	48,986,100	ProSym vs. Actual	0.46%
	Actual-BAI	-134,210	-82,654	-48,515	4,322	-29,509	2,162	6,822	80,977	20,436	73,239	-7,228	-47,384	-161,542	BAI vs. ProSym	-0.13%