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Witness: Shawn Schukar
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

DIRECT TESTIMONY

OF

SHAWN E. SCHUKAR

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

****DENOTES HIGHLY CONFIDENTIAL INFORMATION****

St. Louis, Missouri
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OF

SHAWN E. SCHUKAR

CASE NO. ER-2007-0002

I. INTRODUCTION

Q. Please state your name and business address.

A. Shawn Schukar, Ameren Energy, Inc., One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Energy and what are your responsibilities relating to off-system sales for AmerenUE?

A. I am the Vice President of Ameren Energy. In that capacity, I am responsible for the short-term management of Union Electric Company d/b/a AmerenUE's ("Company" or "AmerenUE") generation, which is presently included in the generating resources which are the subject of the Joint Dispatch Agreement ("JDA") among AmerenUE and certain of its affiliates. As part of the short-term management of AmerenUE's generating assets, I manage AmerenUE's off-system sales.

Q. Please describe your educational background, work experience and duties of your position.

A. I received a Bachelors degree in Mechanical Engineering from the University of Illinois in 1984 and a Masters of Business degree from the University of Illinois in 2001. I joined Illinois Power Company ("Illinois Power") in 1984 as a power plant engineer. I subsequently held several power plant positions from 1986 through 1996 including positions in plant performance management, plant operations management, and plant engineering management. In 1996 I became responsible for the generation control function which included the dispatch and short-term energy sales associated with the Illinois Power control area. I was responsible for generation control, energy trading and energy marketing from 1997 – 1999. I then managed the retail pricing and risk management portions of the business from 1999 – 2000. I managed the transmission operations from 2000 through 2003. I became responsible for the transmission, generation dispatch and gas control functions at Illinois Power from 2003 through 2004. In 2004 I became responsible for the Illinois Power field operations and continued with that responsibility after Ameren Corporation's acquisition of Illinois Power until 2005. As noted above, I am now responsible for the short-term management of the generation included in the JDA.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I am providing testimony in support of the level of off-system sales margins and related costs within the cost of service utilized for the purpose of setting AmerenUE's rates. In addition, I discuss an alternative off-system sales margin sharing mechanism that could be used to mitigate the risks associated with off-system sales margins for AmerenUE and its customers, as well as provide a balanced incentive for AmerenUE to improve revenues and lower costs in order to maximize off-system sales margins. Finally, I address the market operation charges incurred by AmerenUE as a participant in the Midwest Independent Transmission System Operator, Inc. ("MISO").

Q. Please summarize your testimony and conclusions.

A. 1. AmerenUE's opportunities to realize off-system sales margins are dependent on its load serving obligations, generation resources, and market prices for energy.

To the extent that the test year is not representative of these factors, test year off-system sales margins must be normalized and adjusted for known and measurable changes. The necessary specific adjustments and normalizations include: (1) the elimination of the JDA, as discussed in detail in the direct testimony of AmerenUE witness Warner L. Baxter; (2) the expiration of the 1987 Power Supply Agreement with Electric Energy, Inc. ("EEInc."), as addressed by Mr. Baxter and in the direct testimony of AmerenUE witnesses Michael L. Moehn and Robert C. Downs; (3) the addition of Noranda Aluminum, Inc. as a retail customer; (4) the transfer of the Metro East (Illinois) service territory to AmerenCIPS; (5) the inclusion of the Taum Sauk pumped storage facility for the full test year, as addressed in Mr. Baxter's direct testimony; (6) the addition of several gas peaker units that AmerenUE purchased in 2006, as addressed in Mr. Moehn's testimony, and additional capacity added at the Callaway Plant in 2005 as discussed in the direct testimony of AmerenUE witness Charles D. Naslund; (7) weather normalization of load, addressed in the direct testimony of AmerenUE witness Richard A. Voytas; (8) the extraordinary 2005 hurricane season as I will address later in my testimony; (9) the extraordinary interruption in rail transportation of coal that occurred in 2005, as addressed later in my testimony and in the direct testimony of AmerenUE witness Robert K. Neff; and (10) adjustments for known and measurable increases in AmerenUE coal and coal transportation costs, which are also discussed in Mr. Neff's direct testimony.

2. AmerenUE incorporated all of these adjustments in its production cost model (the operation of which is addressed in the direct testimony of AmerenUE witness Timothy D. Finnell) to determine the appropriate normalized level of off-system sales margins to include as a reduction to the Company's cost of service. Using the model, I have

determined that the appropriate level of off-system sales margins to use in setting AmerenUE's rates is $180 million annually.

3. As an alternative to selecting a fixed dollar amount for off-system sales margins to be included in AmerenUE's cost of service, the Company, subject to Commission approval, could implement a sharing mechanism which would mitigate the substantial risks associated with the variability of off-system sales margins for both AmerenUE and its customers, and would provide a balanced incentive for AmerenUE to improve revenues and lower costs in order to maximize off-system sales margins. The structure of such a mechanism should include a very low "base" level of off-system sales margins in base rates, which are achievable under most conditions. Then AmerenUE and its customers should share off-system sales margins above that amount. Customers should receive the lion's share of the off-system sales margins just above the base amount, with the Company's share of the margins increasing to higher levels to provide it with an incentive to lower its production costs and maximize off-system sales revenues.

4. Pursuant to the Missouri Public Service Commission's order in Case No. EO-2003-0271, AmerenUE became a member of the MISO. As a member of the MISO, AmerenUE is a market participant that purchases and sells power in the MISO market. As a result of these activities, AmerenUE incurs unavoidable administrative and market costs. The level of costs that are included in AmerenUE's cost of service has been adjusted using expected MISO costs for 2006, which will be updated to include actual 2006 MISO costs when the test year is updated. The 2006 costs are being used to take into account the initial inefficiencies and resulting higher costs experienced at MISO during the initial operations of MISO's Day 2 Markets.

An executive summary of my testimony is contained in Attachment A.

Q. How have you organized the remainder of your testimony?

A. The remainder of my testimony is organized into four sections. Section III discusses the off-system sales margins that are appropriate and consistent with other portions of the cost of service calculation for AmerenUE in this rate case. Section IV of my testimony discusses the methodology I utilized to determine the off-system sales margins, including my adjustments for known and measurable changes to the test year information that affect the level of megawatts ("MW") and megawatt-hours ("MWh") that are available for off-system sales. I also explain my adjustments for anomalous and unusual factors that affected the market price of power in the test year. Section V explains how a sharing mechanism could be used to address uncertainties regarding the proper level of off-system sales margins that should be reflected in base rates. And, finally, Section VI of my testimony explains the MISO market operations charges that are included in the cost of service.

III. THE NEED FOR ADJUSTMENTS TO TEST YEAR OFF-SYSTEM SALES MARGINS

Q. How do you define off-system sales margins?

A. I define off-system sales margins as gross off-system sales revenues minus the fuel costs associated with those revenues.

Q. How should off-system sales margins be considered in the determination of AmerenUE's rates?

A. I have determined that the appropriate level of AmerenUE margins associated with off-system sales for inclusion in AmerenUE's cost of service is $180 million per year. This determination is based on adjustments to and normalization of test year information for known and measurable changes and unusual market conditions experienced in 2005.

Q. Why was the normalized level of off-system sales margins determined by modeling rather than utilizing the actual test year off-system sales?

A. There were several known changes that have directly affected off-system sales margins. These changes, which require adjustment to test year results in order to determine the appropriate normalized level of off-system sales margins, include: (1) The elimination of the JDA; (2) the expiration of the 1987 Power Supply Agreement with EEInc.; (3) the addition of Noranda as a retail customer; (4) the transfer of the Metro East service territory; (5) the inclusion of the Taum Sauk pumped storage facility for the full test year; (6) the addition of the Audrain, Goose Creek, and Raccoon Creek gas-fired peaking facilities that AmerenUE purchased in 2006 and an increase in the capacity of the Callaway Plant; (7) weather normalization of load; (8) the extraordinary 2005 hurricane season, (9) interruptions in rail transportation of coal in 2005; and (10) adjustments for known and measurable increases in AmerenUE's coal and transportation costs.

The best way to accurately measure the combined effect of these factors on off-system sales margins is with a production cost model. A production cost model can simulate the operation of the system with all adjustments to supply, demand, and market prices in place.

IV. METHODOLOGY USED TO ADJUST TEST YEAR OFF-SYSTEM SALES MARGINS

Q. What production cost model was used to calculate a normalized level of off-system sales margins utilized to set AmerenUE's revenue requirement in this case?

A. The $180 million in annual off-system sales margins was derived from the same PROSYM model run that was used to determine the production costs utilized by AmerenUE witness Gary S. Weiss in calculating AmerenUE's revenue requirement. The

PROSYM model incorporates load requirements, generation and generation availability, any existing wholesale sales, and hourly market prices. As discussed in detail in Mr. Finnell's direct testimony, PROSYM is a production cost model that simulates the dispatch of the AmerenUE generation fleet to supply existing commitments including native load and wholesale sales, while buying or selling energy economically. As Mr. Finnell explains, the model has been calibrated against historical information to ensure that the model accurately reflects the AmerenUE system and economic opportunities associated with the dispatch of the system. Mr. Finnell's direct testimony demonstrates a very accurate match between modeled results and actual results, validating the use of the model for determining normalized off-system sales margins.

Q. How are off-system sales margins derived from the PROSYM output?

A. PROSYM simulates the dispatch of AmerenUE's system by utilizing the lowest cost resources to meet the hourly load and operating reserves requirements. As part of its hourly dispatch, the model identifies opportunities for off-system sales based on the generation that is not being utilized to serve native load that has dispatch costs below the hourly market price. The model also identifies opportunities to buy from the market to reduce the cost to serve native load and offset AmerenUE's generation costs. The simulated off-system sales margins are determined based on the difference between the hourly market price achieved and AmerenUE's variable costs of producing the MWhs that are sold to the market.

Q. What are the major inputs and assumptions included in the PROSYM model run?

A. As discussed in more detail by Mr. Finnell, the major inputs include AmerenUE's hourly loads, unit operating characteristics, fuel and emission costs, variable operation and maintenance ("O&M") costs, and hourly market prices for purchases and sales.

Q. Do the inputs and assumptions reflect actual conditions for the test year?

A. The inputs are based on test year conditions with adjustments for known and measurable changes and for extraordinary market conditions, including those I listed above.

Q. Will you describe these inputs and how you made adjustments to test year conditions?

A. Mr. Finnell provides a comprehensive explanation of the inputs that were used in the PROSYM model. I will explain the market price of energy that I used to determine the off-system sales and economic purchases, and how it was adjusted for unusual market conditions in 2005. I will also explain how fuel and emission costs that were used to dispatch the system were adjusted to be consistent with the market price of energy. Finally, I will explain how and why off-system sales margins were adjusted to reflect known and measurable increases in AmerenUE's coal and transportation costs after simulating the dispatch in the PROSYM model.

Q. What market prices were utilized to determine the off-system sales and economic purchases?

A. The market prices were determined based on a three-year average of prices for each month during the period from January 2003 through December 2005, with adjustments to account for the effect of the extraordinary hurricane season and the rail transportation disruptions in 2005. The average market price for that period of time, with these adjustments, was $35.71 per MWh.

Q. Why are you normalizing the actual test year market prices for the determination of off-system sales margins?

A. The unadjusted test year market prices do not reflect an appropriate, normalized market price. As I discussed earlier, the test year had several unusual events that significantly affected both fuel prices and market prices for wholesale energy. The most significant impact resulted from the extraordinarily destructive hurricane season. Hurricanes Katrina and Rita reduced supplies of natural gas and oil, and increased the cost of these fuels dramatically. While the increase in gas prices is generally attributed to Hurricane Katrina, the price of gas had in fact increased previously as a result of Hurricane Dennis, even though Dennis did not directly affect gas producing areas in the Gulf of Mexico. The effect of the hurricanes on the supply and price of natural gas and the related power costs was significant but only temporary and, consequently, not reflective of normalized prices for natural gas and power. Schedules SES-1 and SES-2 show the dramatic, temporary increase in natural gas and energy prices starting in July 2005 and show just how unusual 2005 was due to the hurricanes. Moreover, the graphs show that the price increases were temporary because the prices of power and gas have already come down to levels similar to those observed prior to the 2005 hurricane season.

Another event affecting the market and distorting market prices in 2005 was the start of the MISO Day 2 energy markets in April 2005. The effect of the MISO personnel learning the systems and the operation of generation in the MISO market footprint initially resulted in inefficient, overly conservative generation dispatch. The MISO-dispatched units maintained a "safety margin" as the operators learned how to manage the generation within the MISO footprint to react to load and net scheduled interchange changes that occurred as a result of weather, load ramp periods, and market activity. As the MISO market operators have become more accustomed to the MISO operations, they have been able to decrease the safety margin and provide a more efficient dispatch. While the inefficiencies associated with the initial MISO dispatch could result in both higher and lower market prices, it is clear the inefficient dispatch affected the market prices and generation availability. Because of this effect, utilizing several years of information provides a more normal representation of market prices.

A third factor that affected market prices was the rail transportation disruptions that occurred in 2005 that reduced the coal inventories of many electric generating companies, including AmerenUE, and caused those companies to put in place coal conservation plans. The effect of the coal conservation plans was to decrease energy supplies and increase market prices through the end of 2005, further constraining generation output and prices.

Finally, the summer of 2005 was one of the warmer summers on record affecting both the load and market prices. The National Climatic Data Center reported that 2005 was the 13th warmest year on record with the summer being the 17th warmest. Warmer than normal weather across the Midwest during the summer of 2005 resulted in higher loads and higher than normal prices for that period. The warmer than normal conditions throughout the Midwest are depicted on Schedule SES-3.

As a result of all of the issues that affected the market during the test year but are not expected to recur in the period during which the rates that will be set as a result of this case will be in effect, it is appropriate to make adjustments to the test year prices for these events.

Q. You mentioned that you normalized using a three-year average of power prices. Please explain why using a three-year average is appropriate.

A. An important reason is because the summer of 2005 was, as discussed above, one of the hotter summers on record in the Midwest. The effect of warmer-than-normal weather was threefold. First, it drove up the amount of generation that was necessary to serve native load and increased the cost of generation available for sales. Second, it reduced the amount of generation that was available for off-system sales. And third, it increased the market price of energy.

Because the PROSYM model utilizes weather-normalized loads, which would result in lower loads and therefore more generation available for off-system sales than in the test year, utilizing the non-normalized, elevated test year prices would overstate the off-system sales margins that would be expected during the period when rates set in this case will be in effect. (The opposite would be true if the test year were cooler than normal). Utilization of more than one year of price data will help to limit the impact on power prices of an abnormally hot or abnormally cool year.

Another important reason to use multi-year averages to normalize prices is that such averages remove peaks and valleys that might otherwise distort prices if too narrow of a snapshot is used. This is particularly true when dealing with highly volatile commodity prices like the price of electricity.

Q. Why is the three-year period beginning January 2003 the appropriate time period to use to determine the price of power?

A. Utilizing those three years of market information will allow relatively current information to be used to determine off-system sales margins while also utilizing a sufficiently long time period to average out some of the price swings associated with variations in monthly weather and other factors. I elected to use a three-year average, although even a four- or five-year average would also probably have been appropriate because it would provide more data points over which to calculate the average. However, the level of gas prices more than three years ago was substantially lower than current and expected future gas prices. The use of the older data may not have provided data that represented normalized prices for the test year.

Q. How did you apply three years of price data to your simulation of the single adjusted test year in PROSYM?

A. Prices for each month were set to the average of the three prices in the corresponding months during the period January 2003 through December 2005. For example, the October prices were set at the average of the October 2003, October 2004 and October 2005 prices, with appropriate adjustments to the monthly data to take into account the anomalous events discussed below.

Q. What adjustments for anomalous events were made to the price data for the three-year period?

A. Two adjustments were made to the three-year average of prices. The first adjustment was to the off-peak power prices for the period of July 2005 through December 2005. This adjustment was made to address the issues associated with the rail transportation disruptions that affected coal deliveries and resulted in companies, such as AmerenUE, implementing coal conservation plans for some period. The second adjustment was an adjustment to peak power prices to account for the effect of the active 2005 hurricane season. This adjustment was for the period of August through December. This adjustment addressed the impact associated with natural gas prices associated with Hurricanes Dennis, Katrina and Rita.

Q. Why was an adjustment needed for the rail transportation disruptions?

A. The rail disruptions that occurred in 2005 resulted in a reduction in the amount of Powder River Basin (Wyoming) coal deliveries throughout the region which affected many utilities. The result was that several companies, including AmerenUE, implemented coal conservation strategies that either reduced the amount of power that was offered into the market or increased the offered market price or both. This increased the off-peak market prices, since coal is almost always on the margin in the off-peak periods of the last six months of the year. As can be seen in Schedule SES-4, the off-peak prices for the last 6 months of 2005 were significantly higher than for previous years.

Q. How did you adjust for the impact of rail transportation disruptions?

A. Off-peak prices for electricity are strongly influenced by the price of coal because power during off-peak periods is typically generated by baseload coal units that are not being used to serve native load. If coal prices are stable, then under normal conditions off-peak prices for electricity will also be stable. To illustrate this, I requested a regression analysis of the relationship between the off-peak power prices in the first half of the year and off-peak power prices in the second half of the year. The regression analysis demonstrated that under normal conditions (i.e. when there were no rail transportation disruptions), off-peak power prices in the first half of a year are a good predictor of off-peak prices in the second half of the year. To adjust off-peak power prices to account for rail transportation disruptions that occurred in the second half of 2005, I used this relationship to arrive at a normalized level of off-peak market prices for the second half of 2005 based on the observed off-peak power prices for the first half of 2005. In other words, I applied the mathematical results of the regression analysis to 2005 off-peak prices from the first half of the year to calculate normalized off-peak power prices for the second half of the year, which in effect then excludes the impact of the rail transportation disruptions. For example, applying these results yields a normalized July 2005 off-peak power price $20.90 per MWh versus the actual, distorted off-peak power price of $28.57 per MWh.

Q. Does this adjustment to off-peak prices during the second half of 2005 produce reasonable results?

A. Yes. The resulting adjustment to the average off-peak price for the last six months of 2005 is a decrease of **[redacted]** per MWh. This is consistent with the difference in off-peak market prices between the second half of 2004 and the second half of 2005. The actual off-peak average for the second half of 2005 was $31.06 per MWh, which is more than $15.00 per MWh higher than in 2004. This indicates that the **[redacted]** per MWh off-peak adjustment to market prices to account for the 2005 rail transportation disruptions is reasonable.

Q. How did you adjust the on-peak prices for the period from August 2005 through December 2005 to account for unusual conditions resulting from the 2005 hurricanes?

A. The hurricane related increase in prices of oil and natural gas caused the cost of the electric generation fired by these fuels to increase dramatically. Since oil- and gas-fired units are often on the margin (i.e. these fuels set the electricity price when on the margin) during peak periods, the hurricanes had a dramatic effect on the on-peak market prices during the months that followed the hurricanes. If the actual on-peak prices for power for the unusual second half of 2005 were to be used to calculate off-system sales margins, the level of off-system sales margins would be significantly overstated.

At my direction, a regression analysis was conducted to measure the impact of the spot price of natural gas on the spot market price for on-peak electric energy in the AmerenUE region. The regression analysis showed that changes in the spot price of natural gas accounted for a significant portion of the variation in spot on-peak electric energy prices. The relationship between gas prices and the spot market price for on-peak electric energy from before the hurricanes was used to adjust the hurricane-affected on-peak prices of power for the period of August through December 2005.

Q. Does this adjustment to on-peak prices during the second half of 2005 produce reasonable results?

A. Yes. During 2004, spot prices for natural gas were similar to the level of natural gas prices that are presently being experienced now that the effects of the hurricanes have dissipated. Since natural gas prices affect energy prices during peak hours, it is reasonable to expect that periods with similar natural gas costs would result in similar on-peak energy prices. The average adjusted on-peak market price for 2005 for the period August through December was $54.03 per MWh. This compares to the average on-peak price in 2004 for the same period of $42.42 per MWh. While the adjusted on-peak power price for the second half of 2005 is still much higher than the corresponding price in 2004, this is not surprising since other impacts such as weather, coal conservation due to the rail transportation disruptions, and the slight increases in market fuel cost unrelated to the hurricanes may have affected on-peak energy prices as well.

Q. Did you also adjust for the effect of the hurricanes on the price of natural gas used in AmerenUE's gas-fired generation?

A. Yes. Since the hurricanes also affected natural gas prices during the August 2005 through December 2005 period, I also made the same type of adjustment to the price of natural gas.

Q. What fuel and emission costs were utilized to dispatch AmerenUE's generating units in the PROSYM model?

A. The period used to determine the dispatch costs of each unit was consistent with the period used to determine the adjusted market prices for power. This consistency is necessary because AmerenUE and the other market participants all dispatch their units at the market price of incremental fuel usage and emissions allowances, which produces a relationship between AmerenUE's dispatch costs and the market price for power. For the purpose of modeling the dispatch of the system, the market prices of coal, gas, emissions, and wholesale energy consequently need to be consistent.

Q. What AmerenUE fuel costs were used to calculate the off-system sales margins?

A. The coal and nuclear costs were based on the known costs associated with already executed fuel contracts with prices that will take effect as of January 2007 as explained in Mr. Neff's and Mr. Finnell's direct testimony. AmerenUE's fuel costs for natural gas are based on the spot market prices for natural gas during the January 2003 – December 2005 period of time with appropriate adjustments for the impact of the 2005 hurricane season.

Q. Why are the fuel costs associated with system dispatch based on market prices while the fuel costs used to determine the off-system sales margin are based on UE's contract costs?

A. As I mentioned previously, the system is dispatched based on the incremental fuel cost (i.e., the applicable market price), which will generally differ from AmerenUE's average cost of fuel. Once the system is dispatched, however, the actual margin that AmerenUE receives from any off-system sale is the difference between the hourly energy price and AmerenUE's actual cost of generation, which is based on AmerenUE's actual cost of fuel. The utilization of the incremental or market cost of fuel for dispatch and the actual cost of fuel to determine margins is consistent with the AmerenUE's dispatch and off-system sales margin determination.

V. A SHARING MECHANISM TO ADDRESS UNCERTAINTIES ASSOCIATED WITH OFF-SYSTEM SALES MARGINS

Q. You previously explained that based on your adjustments to test year data, you estimate that an off-system sales margin of $180 million per year should be included in AmerenUE's cost of service. Do you have any concerns about the uncertainty associated with off-system sales margins and the estimated adjusted test year level of such margins that you recommend to be included in AmerenUE's cost of service in this case?

A. Yes. AmerenUE faces the significant risk of not earning the expected level of off-system sales margins because of a variety of uncertainties regarding fuel costs, power prices, native load requirements, and generation availability.

Q. Please explain why generation availability affects off-system sales margins.

A. AmerenUE has worked diligently over the years to improve the availability of its power plants as discussed in the direct testimonies of AmerenUE witnesses Mark C. Birk and Charles D. Naslund. These improvements in availability have been made notwithstanding the advanced age of many of the units in AmerenUE's generating fleet. Since AmerenUE has already achieved outstanding plant availability, the opportunities for additional improvement are less than the potential for unforeseen problems that would reduce availability. Given the detrimental impact that only a slight reduction in generation availability can have on off-system sales, AmerenUE would be at significant risk of not achieving the estimated off-system sales margins that I have calculated.

Q. Please explain why fuel costs and power prices impact off-system sales margins.

A. Prevailing power prices directly impact the level of revenues that can be collected through off-system sales of available power, and the margins that can be achieved from those sales. Fuel costs are the most significant cost that must be deducted from off-system sales revenues, so they too directly impact the margins that AmerenUE will collect. Any change to market power prices or fuel costs will lead to a corresponding change, up or down, in AmerenUE's off-system sales margins.

Q. How do native load requirements affect off-system sales margins?

A. Native load requirements affect the amount of power that is available for AmerenUE to sell. For example, on a hotter than normal October day, AmerenUE will have far less excess power to sell off-system than it typically does during a normal October day. If AmerenUE has less power to sell, it will earn less in margins, all other things being equal. Conversely, if AmerenUE has excess power that it can sell, margins will increase, all else being equal.

Q. Do these uncertainties affect both AmerenUE and its customers if a single estimate of off-system sales margins is used in calculating AmerenUE's revenue requirement?

A. Yes. Customers and AmerenUE face the same risk that the level of off-system sales margins used in the cost of service will prove to be inaccurate due to changes in fuel costs, power prices, native load requirements, generation availability or other factors. The customers' risk is that the off-system sales margins will be set at a level that is too low, and the Company's risk is that the margins will be set at a level that is too high. Given the large magnitude of the dollars involved, the impact of selecting an incorrect level of margins on both the Company and its customers could be substantial.

Q. Are there any options to address the uncertainties concerning off-system sales margins you have just described?

A. Yes. As an alternative to selecting a set amount of off-system sales margins for inclusion in AmerenUE's cost of service, the Company could use, if approved by the Commission, a sharing mechanism for off-system sales margins to protect itself from the risk that realized off-system sales margins fall below the level that is included in rates, while also providing customers with benefits if off-system sales margins exceed the level included in rates.

Q. How would such a sharing mechanism be structured?

A. The sharing mechanism would include a "base" level of off-system sales margin revenues in AmerenUE's cost of service, and all off-system sales margins above the base level would be shared between AmerenUE and its customers. The amount shared with AmerenUE's customers would be determined annually or quarterly and credited against customers' retail rates.

Q. How would the base level of off-system sales margins be determined for the purpose of this sharing mechanism?

A. The base level would be determined as a level of off-system sales margins that AmerenUE would be likely to achieve under most circumstances, i.e., even under conditions such as unusually low power prices or unusually high generation outages.

Q. Given that you determined that an appropriate level of test year off-system sales margins is $180 million, if a sharing mechanism is used by the Company, at what level would you propose to set the base level, and how would you propose to share margins under this mechanism?

A. If a sharing mechanism is used, I would propose to set the base level of off-system sales margins at $120 million per year. I selected this base level based on the variability of power prices during the three-year period that I studied (2003-2005), and my views on generation availability risk and native load variability. I believe it would be likely that AmerenUE could achieve this level of off-system sales margins even under relatively adverse market and operational conditions. I would also propose that, until off-system sales margins reach $180 million, customers would share 80% of the margins above the $120 million threshold. For margins in excess of the $180 million level, AmerenUE and its customers would share equally in the increment until total off-system sales margins reach a cap of $360 million. I would then propose that AmerenUE's customers retain 100% of the off-system sales above $360 million. I based the $360 million cap on my view of market price variability, opportunities to improve generation availability and native load variability. The fact that customers would receive 100% of the off-system sales margins above the cap gives customers additional opportunities for rate relief in the event unusually high power prices or other factors result in extremely high off-system sales margins which could likely not be achieved under normal market and operating conditions. The parameters of this sharing mechanism are depicted on the grid below.

Level of Off-System Sales Margins (in millions of $)	**Customer Share**	**AmerenUE Share**	**Effective Share for Customers**
$0 - $120	100%	0%	100%
$121- $180	80%	20%	100% - 93%
$181 - $360	50%	50%	92% - 72%
Over $360	100%	0%	72% or more

Q. Are you proposing to implement this off-system sales sharing mechanism at this time?

A. No, not at this time. However, the mechanism discussed above could be implemented as part of the resolution of this case. The sharing mechanism could also be implemented to provide AmerenUE with incentives to strive to maximize off-system sales margins if a fuel and purchased power adjustment clause were to be implemented, as addressed in Mr. Baxter's testimony.

VI. MISO DAY 2 MARKETS OPERATIONS CHARGES

Q. What are MISO Day 2 market operations charges?

A. The MISO started its so-called "Day 2" energy markets in April 2005. There are several charges that AmerenUE must incur as a result of being in the MISO energy market. These charges include but are not limited to Market Administration, Uninstructed Deviation, Revenue Neutrality Uplift, Revenue Sufficiency Guarantee, Miscellaneous, and Congestion Charges.

Q. Why is it appropriate for AmerenUE to include these charges in its cost of service?

A. In Case No. EM-96-149, the Commission required as a condition to its approval of the Stipulation and Agreement, that AmerenUE "file or join in the filing of a regional ISO proposal at the Federal Energy Regulatory Commission that eliminates pancaked transmission rates, that is consistent with the ISO guidelines set out in FERC Order 888, …". To fulfill this requirement, AmerenUE sought approval to join the MISO. That approval was obtained from the Commission in Case No. EO-2003-0271, where the Commission approved a Stipulation and Agreement that provided: "AmerenUE's decision to participate on an interim and conditional basis in the Midwest ISO under the terms provided for in this Stipulation is prudent and reasonable". As a MISO participant, AmerenUE is subject to these MISO charges. These charges are therefore a required and integral part of serving native load customers which must be included in AmerenUE's cost of service.

Q. Has AmerenUE done anything to manage the charges associated with the MISO markets and if so what?

A. Yes. Although many of the charges associated with the MISO markets are allocated on a load ratio share basis, some of the charges, such as Revenue Sufficiency Guarantee, are allocated based on deviations between day-ahead and real-time markets. The best way to manage these charges is to manage the deviations that occur as a result of load forecast error, unit operation, etc. If all companies managed the deviations in the same manner one would expect that the allocation would be similar to the level of allocation associated with load ratio share allocations. From the start of the market through April 2005, AmerenUE has managed its operations such that the allocation of the charges is just **[redacted]** as compared to a load ratio share of 13.64%. This demonstrates that AmerenUE's efforts to limit these uplift costs is producing positive results.

Q. What specific level of MISO charges is included in AmerenUE's cost of service in this case?

A. Because the level of costs during the MISO market start-up were higher than those costs are expected to be in the future, the Company has reduced the actual MISO charges in its cost of service for this case to its forecasted amount for 2006, which we believe is more appropriate and fair. When the case is updated, actual calendar year 2006 MISO charges should be substituted for these forecasted amounts.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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.	)))))	Case No. ER-2007-0002

AFFIDAVIT OF SHAWN SCHUKAR

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Shawn Schukar, being first duly sworn on his oath, states:

1. My name is Shawn Schukar. I work in the City of St. Louis, Missouri, and I am employed by Ameren Energy, Inc. Vice President of Ameren Energy.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 24 pages, Attachment A and Schedules SES-1 through SES-4, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Shawn Schukar
Shawn Schukar

Subscribed and sworn to before me this 6th day of July, 2006.

Carolyn J Woodstock
Notary Public

My commission expires: May 19, 2008

CAROLYN J. WOODSTOCK
Notary Public - Notary Seal
STATE OF MISSOURI
Franklin County
My Commission Expires: May 19, 2008

EXECUTIVE SUMMARY

Shawn E. Schukar

Vice President, Ameren Energy

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I am providing testimony in support of the level of off-system sales margins and related costs used to determine AmerenUE's cost of service for the purpose of setting the Company's rates. In addition, I discuss an alternative off-system sales margin sharing mechanism that could be used to mitigate the risks associated with off-system sales margins for AmerenUE and its customers, as well as provide a balanced incentive for AmerenUE to reduce costs and increase revenues in order to maximize off-system sales margins. Finally, I address the market operation charges incurred by AmerenUE as a participant in the Midwest Independent Transmission System Operator, Inc. ("MISO").

In summary, my testimony states that:

1. AmerenUE's opportunities to realize off-system sales margins are dependent on its load serving obligations, generation resources, and market prices for energy. Test year off-system sales margins must be normalized and adjusted for known and measurable changes, which include: (1) the elimination of the Joint Dispatch Agreement, as discussed by AmerenUE witness Warner L. Baxter; (2) the expiration of the 1987 Power Supply Agreement with Electric Energy, Inc. ("EEInc."), as addressed by Mr. Baxter and by AmerenUE witnesses Michael L. Moehn and Professor Robert C. Downs; (3) the addition of Noranda Aluminum, Inc. as a retail customer; (4) the transfer of the Metro East (Illinois) service territory to AmerenCIPS; (5) the inclusion of the

Taum Sauk pumped storage facility for the full test year, as addressed by Mr. Baxter; (6) the addition of several gas peaker units that AmerenUE purchased in 2006, as addressed by Mr. Moehn; and additional capacity added at the Callaway Plant in 2005, as discussed by AmerenUE witness Charles D. Naslund; (7) weather normalization of load, addressed by AmerenUE witness Richard A. Voytas; (8) the extraordinary 2005 hurricane season, which I discuss; (9) the extraordinary interruption in rail transportation of coal that occurred in 2005, as discussed by myself and by AmerenUE witness Robert K. Neff; and (10) adjustments for known and measurable increases in AmerenUE coal and coal transportation costs, which are also discussed by Mr. Neff.

2. AmerenUE incorporated all of these adjustments in its production cost model (the operation of which is addressed by AmerenUE witness Timothy D. Finnell) to determine the appropriate normalized level of off-system sales margins to include as a reduction to the Company's cost of service. Using the model, I have determined that the appropriate level of off-system sales margins to use in setting AmerenUE's rates is $180 million annually.

3. As an alternative to selecting a fixed dollar amount for off-system sales margins to be included in AmerenUE's cost of service, the Company, subject to Commission approval, could implement a sharing mechanism which would mitigate the substantial risks associated with the variability of off-system sales margins for both AmerenUE and its customers, and would provide a balanced incentive for AmerenUE to maximize off-system sales margins. The structure of such a mechanism should include a very low "base" level of off-system sales margins in base rates, which are achievable under most conditions. Then AmerenUE and its customers should share off-system sales

margins above that amount. Customers would receive the lion's share of the off-system sales margins just above the base amount, with the Company's share of the margins increasing to higher levels to provide it with an incentive to lower its production costs and maximize off-system sales revenues. The parameters of this alternative sharing mechanism are depicted on the grid below.

Level of Off-System Sales Margins (in millions of $)	**Customer Share**	**AmerenUE Share**	**Effective Share for Customers**
$0 - $120	100%	0%	100%
$121- $180	80%	20%	100% - 93%
$181 - $360	50%	50%	92% - 72%
Over $360	100%	0%	72% or more

4. Pursuant to the Missouri Public Service Commission's order in Case No. EO-2003-0271, AmerenUE became a member of the MISO. As a member of the MISO, AmerenUE is a market participant that purchases and sells power in the MISO market. As a result of these activities, AmerenUE incurs unavoidable administrative and market costs. The level of costs that are included in AmerenUE's cost of service has been adjusted using expected MISO costs for 2006, which will be updated to include actual 2006 MISO costs when the test year is updated. The 2006 costs are being used to avoid the inclusion in the revenue requirement of the higher costs resulting from the initial inefficiencies experienced during the initial operations of MISO's Day 2 Markets.