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| Exhibit No.: | |
| Issues: | Sharing of Profit Margins from Off-System Sales; Fuel and Wholesale Electric Prices; and Use of Limits for Off-System Sales |
| Witness: | Michael S. Proctor |
| Sponsoring Party: | MoPSC Staff |
| Type of Exhibit: | Rebuttal Testimony |
| Case No.: | ER-2007-0002 |
| Date Testimony Prepared: | January 31, 2007 |

**MISSOURI PUBLIC SERVICE COMMISSION**

**UTILITY OPERATIONS DIVISION**

# REBUTTAL TESTIMONY

# OF

# MICHAEL S. PROCTOR

**UNION ELECTRIC COMPANY**
**d/b/a AMERENUE**

**CASE NO. ER-2007-0002**

**Jefferson City, Missouri**
**January 2007**

****<u>Denotes Highly Confidential Information</u>****

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**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 MICHAEL S. PROCTOR**

**STATE OF MISSOURI** )
) ss
**COUNTY OF COLE** )

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the following Rebuttal Testimony in question and answer form, consisting of 43 pages of Rebuttal Testimony to be presented in the above case, that the answers in the following Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S. Proctor

Michael S. Proctor

Subscribed and sworn to before me this 30th day of January, 2007.

James Penningroth

Notary Public

My commission expires 10-28-07

JAMES PENNINGROTH
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Oct. 28, 2007

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# REBUTTAL TESTIMONY

# OF

# MICHAEL S. PROCTOR

# UNION ELECTRIC COMPANY
# d/b/a AMERENUE

# CASE NO. ER-2007-0002

**Q. What is your name and business address?**

A. My name is Michael S. Proctor. My business address is 9900 Page Avenue, Suite 103, Overland, MO 63132.

**Q. By whom are you employed and in what capacity?**

A. I am employed by the Missouri Public Service Commission (Commission) as Chief Regulatory Economist in the Energy Department.

**Q. Are you the same Michael S. Proctor who submitted direct testimony in this case?**

A. I am.

## EXECUTIVE SUMMARY

**Q. On what issues have you filed rebuttal testimony in this proceeding?**

A. My rebuttal testimony will address the direct testimony of AmerenUE witnesses Shawn E. Schukar and Timothy D. Finnell. The issues discussed in my rebuttal testimony will include the AmerenUE proposal for a sharing mechanism associated with off-system sales margins. In addition, I will discuss the estimates of fuel prices and wholesale electricity prices used by AmerenUE in its determination of the variable production costs to be included in its cost of service, as well as the impact that this has on AmerenUE's estimate of profit margins from off-system sales. Finally, I will discuss the use of limits that AmerenUE set on its production cost model related to megawatts per hour of off-system sales.

**Q. Can you briefly summarize your rebuttal testimony regarding AmerenUE's proposal for a sharing mechanism associated with profit margins from off-system sales?**

A. Yes. The Missouri Commission should not adopt the AmerenUE proposal for a sharing mechanism associated with profit margins for the following reasons:

1. AmerenUE's filing provides insufficient evidence to support the need for a sharing mechanism;
2. The definition of profit margins from off-system sales lacks the specificity required for the proposed sharing mechanism to be implemented in AmerenUE's tariff;
3. The proposed base level for profit margins from off-system sales was determined from rough calculations based on incomplete information and assumptions that are not valid;
4. The sharing mechanism for customers of 80% of profit margins between AmerenUE's proposed base level up to its "normal" level of profit margins and 50% of profit margins between AmerenUE's "normal" level of profit margins up to twice that level is arbitrary and unfair; and
5. A sharing mechanism for profit margins from off-system sales contributes to AmerenUE's downside risk related to fuel expense.

In summary, the Staff found no aspect of the proposed sharing mechanism associated with off-system profit margins to be acceptable to the Staff.

**Q. Can you briefly summarize your position on fuel prices used by AmerenUE in its production cost model to dispatch its generation?**

A. Yes. AmerenUE used a three-year historical average of fuel dispatch prices after adjusting for the effects of rail transportation and natural gas supply problems associated with the hurricanes that occurred in the summer of 2005. With respect to coal prices, these three-year average prices are not representative of either AmerenUE's actual coal costs or spot market coal prices that it is facing today, and should therefore be rejected. With respect to natural gas prices, three-year average prices are lower than the spot prices that AmerenUE is facing today, and should therefore be rejected.

**Q. Can you briefly summarize your position on estimates of spot electricity prices used by AmerenUE in its production cost model?**

A. Yes. AmerenUE also used a three-year average for spot electricity prices after making adjustments to off-peak prices for rail transportation problems in 2005 and to on-peak prices for natural gas supply problems resulting from the hurricanes in the summer of 2005. While, AmerenUE's off-system prices were consistent in methodology with AmerenUE's fuel dispatch prices, because its fuel dispatch prices were too low, its spot prices for electricity were also too low and are not representative of spot-market electricity prices that it is facing today. Therefore, the Missouri Commission should reject AmerenUE's estimates of spot electricity prices.

**Q. Can you briefly summarize your position on AmerenUE's estimate of normal levels for profit margins from off-system sales?**

A. Yes. Because the contract coal prices used by AmerenUE to determine accounting costs were significantly higher than the dispatch prices used in its production cost model, its filing in this case depicts a situation that is unlikely to occur in the future (i.e., is abnormal, rather than normal). The result of this inconsistency is that AmerenUE's estimate for profit margins from off-system sales is so low that it is outside the range of probable outcomes. Therefore, the Missouri Commission should reject AmerenUE's estimate of normal profit margins from off-system sales.

**Q. Can you briefly summarize your position on the limits that AmerenUE set on megawatts per hour for off-system sales?**

A. Yes. AmerenUE set limits on megawatts per hour for off-system sales based on a combination of analysis and judgment. Under a system of physical transmission rights that existed prior to the Midwest ISO energy markets, physical limits to export capability would be one way to restrict off-system sales to reflect available transmission capability for bilateral transactions. However, with the advent of the Midwest ISO day-ahead and real-time energy market, the matching of energy prices with loads and AmerenUE's incremental cost is the proper way to limit sales, and physical limits are no longer relevant. Finally, in my review of AmerenUE's methods for setting these limits, I found several methodological deficiencies that demonstrate that the limits set by AmerenUE cannot be determined as being reasonable. These deficiencies include:

1. Limits for the 2005 fuel budget were low compared to actual off-system sales for the September 28, 2003 through September 27, 2004 period that were the basis for setting these limits;
2. In setting limits purportedly based on actual 2005 experience, AmerenUE failed to include any supporting analysis of actual off-system sales during this same period compared to those limits; and
3. In setting limits that purportedly reflect the elimination of the Joint Dispatch Agreement, AmerenUE did not add megawatts to the limits it determined for the first three quarters from 2005, and also failed to include any analysis comparing the proposed limits to transfers of energy from AmerenUE to Ameren Energy Generation along with off-system sales during the 2005 period.

Based on these deficiencies, the limits that AmerenUE placed on off-system sales are unreasonable and should be rejected by the Missouri Commission.

## A. REBUTTAL TO AMERENUE's PROPOSED SHARING MECHANISM ASSOCIATED WITH PROFIT MARGINS FROM OFF-SYSTEM SALES

### 1. Insufficient Evidence Given to Support the Need for a Sharing Mechanism

**Q. What were the reasons given by AmerenUE for the Missouri Commission to consider adopting a sharing mechanism associated with profit margins from off-system sales?**

A. AmerenUE witness Mr. Shawn E. Schukar addressed these reasons on pages 18 through 20 of his direct testimony. The reasons given by Mr. Schukar include:

1. The age of AmerenUE's generation fleet results in uncertainty regarding the future availability of those units to provide energy to sell into the spot market [p. 18, lines 14-22];
2. Changing fuel prices and spot market prices for electricity directly impact the margins that AmerenUE will receive [p. 19, lines 3-8]; and
3. Changes in weather that will affect the amount of native load that AmerenUE has to serve from its generation fleet will affect the amount of available generation it will have to sell into the spot market [p. 19, lines 10-15].

**Q. Do you believe the preceding statements are accurate and provide evidence of the need for a sharing mechanism for profit margins from off-system sales?**

A. I can agree that unit availability, changing fuel prices and spot market prices and weather impacts on load are factors that can effect profit levels from off-system sales. But this is not sufficient evidence to support the need for a sharing mechanism for profit margins from off-system sales.

First, with regard to the age of AmerenUE's generation fleet and unit availability, there is testimony in this case regarding the availability of each of AmerenUE's generating units. If AmerenUE believes that these unit availabilities are too high because of their age, it should have presented a unit-by-unit determination of what levels of availability it deems to be appropriate, including the specific reasons for its determination. Moreover, there is no evidence in the record to support the contention that as the age of AmerenUE's generation units have increased, the availability of those units has decreased. However, it appears from Mr. Schukar's work papers supplied in response to Staff DR. No. 485, that the age of the AmerenUE generating units is not the concern; rather, it is the variability in unplanned outages. Mr. Schukar estimates that the variability in unplanned outages could account for an increase of as much as 4.6% in the forced outage rate for total AmerenUE coal capacity.

Second, while changing fuel prices and wholesale electric prices impact the level of profit margins, AmerenUE has not presented any studies to show what this impact is. In essence, since there is a high level of correlation between fuel prices and spot market prices for electricity, the net impact of changing prices on profit margins could be fairly minimal, and I will present evidence to show that this is the case.

Third, changing weather impacts the amount of generation needed to serve native load, and Mr. Schukar's work papers indicate that this impact could be as large as 2.7% of native load.

**Q. If AmerenUE were to properly pursue a proposal for the sharing of profit margins from off-system sales, what specific studies do you recommend that it perform to determine need?**

A. There would be several elements that should be included in such a study, and I would be more than willing to be involved with AmerenUE in the specific design. For purposes of this testimony, I will present a basic structure that should be followed.

**1. Determine the specific uncertain variables.** This would include all of the key variables that are likely to provide variations in profit margins from off-system sales, such as: 1) spot-market prices (on-peak and off-peak); 2) fuel prices of units that will make off-system sales (e.g., coal and natural gas); 3) weather (impact on load and spot-market prices); and 4) generation unit forced outages (impact on availability of generation).

**2. Determine statistical measures for the uncertain variables.** For each key variable, a distribution associated with historical levels of variation need to be determined. In looking at historical spot-market price levels, I found that it is critical to separate out various components of variation, such as variations due to: 1) trend – steady increases/decreases in prices over time; 2) cycles – changes that occur in a repeated pattern over time; and 3) random – variations from trends and cycles that cannot be explained. The distribution by component for AmerenUE's on-peak and off-peak spot- market prices is shown below.

Statisical Variability for AmerenUE Prices

**** Highly Confidential**

**Statistical Variability for On-Peak Prices ($/MWh)**

| Summary | VAR | % | SD | Modeled | Not Modeled |
|---|---|---|---|---|---|
| Trend | | | | | |
| Cycle | | | | | |
| Random | | | | | |
| Total | | | | | |
| Mean = | | SD as % Mean = | | | |

Total Variability As % Mean

**Statistical Variability for Off-Peak Prices ($/MWh)**

| Summary | VAR | % | SD | Modeled | Not Modeled |
|---|---|---|---|---|---|
| Trend | | | | | |
| Cycle | | | | | |
| Random | | | | | |
| Total | | | | | |
| Mean = | | SD as % Mean = | | | |

Total Variability As % Mean

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As the above tables show, it is important to separate out the variability of the cyclical component of spot-market prices because this variation is included in the production cost modeling of off-system sales and is already taken into account in the determination of profit



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levels from off-system sales. Moreover, the cyclical pattern in spot prices is correlated with the cyclical patterns for load, both of which are included in the production cost model used to calculate profit margins from off-system sales.

**3. Determine correlations among uncertain variables.** For example, there is a strong correlation between the trend component of on-peak spot prices and natural gas prices, between the trend component of off-peak spot prices and coal prices, and over the past four years, there has also been a strong correlation between off-peak and on-peak spot-market prices for electricity. These correlations are shown on Schedules 1.1 through 1.3 attached to my rebuttal testimony. In addition, there are correlations between monthly, daily and hourly variations in loads and spot prices, both of which are driven by variations in weather.

**4. Set out all of the scenarios involving uncertain variables to be analyzed.** These should be done in a "smart" way by taking into account correlations and using statistical sampling designs to develop scenarios that are representative of the probability distribution of outcomes. Associated with each scenario would be a probability of occurrence.

The results of this type of process are illustrated for a probability distribution associated with fuel prices and spot-market electricity prices on the following table. (Given the limited time and resources available, I only developed a distribution for prices, and was not able to analyze variability associated with loads and forced outages.)

**Estimated Distribution for Prices**

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| Off-Peak | | On Peak | | Original Distribution | Coal Prices | | Natural Gas Prices | |
|---|---|---|---|---|---|---|---|---|
| $/MWh | % Diff | $/MWh | % Diff | | ¢/MMBTU | % Diff | $/MMBTU | % Diff |
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| Off-Peak ($/MWh) | | On Peak ($/MWh) | | Truncated Distribution | Coal (¢/MMBTU) | | Natural Gas ($/MMBTU) | |
|---|---|---|---|---|---|---|---|---|
| From | To | From | To | | From | To | From | To |
| | | | | | | | | |
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The original distribution (upper table) was developed using the mean values from the Staff's filings in my direct testimony (i.e., the mean values in the table are ** ______ **/MWh – off peak, ** ______ **/MWh – on-peak, ** _______ **/MMBTU - coal and ** _____ **/MMBTU – natural gas). The distribution was developed using the standard deviations from historical data for on-peak spot market prices applied to a normal probability distribution. Values for the off-peak spot market price, coal price and natural gas price were then calculated using the correlations shown in Schedule 1.

This initial distribution was truncated based on the range of on-peak spot-market prices that were observed over the past four-year period. The resulting truncated distribution for prices is shown in the lower table. Both distributions are shown on the following graph as a percent of mean.

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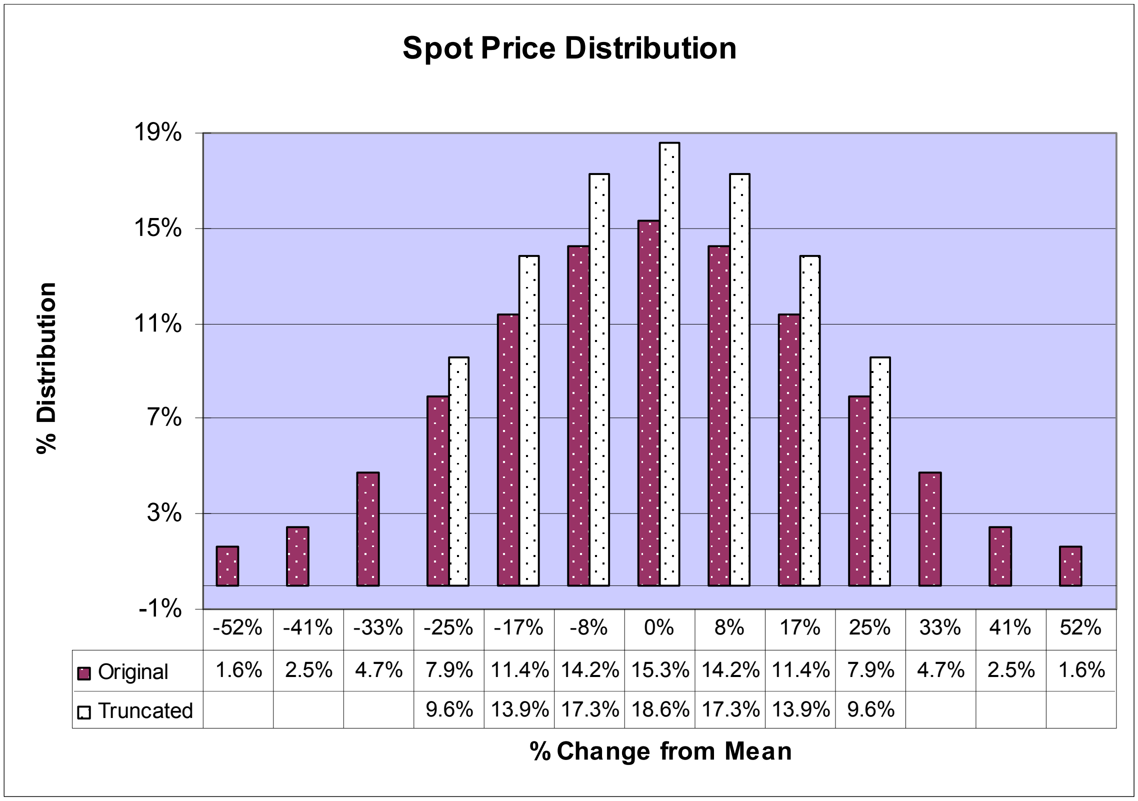


**5. Run production cost models to determine the level of profit margins associated with each scenario.** The objective here is to develop a probability distribution associated with profit margins from off-system sales. To reach that objective, the scenarios and associated probabilities must be converted into levels of profit margins. For purposes of this illustration, Staff witness Michael Rahrer ran the Staff's production cost model for the extreme price scenarios shown at the top and bottom of the estimated price distribution table: 1) at the lower end (** ______ **/MWh – off-peak, ** ______ **/MWh – on-peak, ** ______ **/MMBTU – coal and ** _____ **/MMBTU – natural gas); and 2) at the upper end (** ______ **/MWh – off-peak, ** ______ **/MWh – on-peak, ** _______ **/MMBTU – coal and ** _____ **/MMBTU – natural gas). A complete analysis would include a greater number of price outcomes and production cost runs performed for each of these outcomes.



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The results of these runs in terms of profit margins from off-system sales are presented graphically in Schedule 2 attached to my rebuttal testimony. Two graphs are shown for the scenarios of with and without the Joppa plant. I have included the scenario of without the Joppa plant for purposes of comparison to AmerenUE's results. The values of profit margins from off-system sales between the extremes and the mean were interpolated based on the percentage variation in on-peak spot-market prices.

**Q. Based on the analysis you have performed, what are your conclusions regarding the need for a sharing mechanism for profit margins from off-system sales?**

A. First, I want to note that my analysis has not taken into account all sources of uncertainty that could impact the level for profit margins from off-system sales. Other key variables not in my analysis include variations in: 1) load; and 2) unit forced outages. All of the results are based on production cost runs where these variables were held at normal levels. In order for the Missouri Commission to make a final determination regarding the variability of profit margins from off-system sales, the additional variability from these components would need to be included.

Based on the variability from spot-market prices and prices for coal and natural gas, the impact on the variability of profit margins from off-system sales is relatively small. To see this, consider the following results:

**Profit Margin Variability: With Joppa**

| Distribution Range | | |
|---|---|---|
| Millions | | Prob |
| + or - | $30 | 53.1% |
| + or - | $61 | 80.8% |
| + or - | $91 | 100.0% |

| Downside Risk | | |
|---|---|---|
| Millions | | Prob |
| -$91 | or Greater | 9.6% |
| -$60 | or Greater | 23.5% |
| -$30 | or Greater | 40.7% |

With Joppa, there is over a 50% probability that profit margins from off-system sales will be within the range of ± $30 million, and over an 80% probability of being within a range of ±

$61 million. Moreover, there is less than a 25% probability that AmerenUE faces a downside risk of profit margins dropping $60 million below the mean level that would be included in traditional rates.

The variability in profit margins from off-system sales is lower for the case without Joppa.

**Profit Margin Variability: Without Joppa**

| Distribution Range | | | Downside Risk | | |
|---|---|---|---|---|---|
| Millions | | Prob | Millions | | Prob |
| + or - | $22 | 53.1% | -$67 | or Greater | 9.6% |
| + or - | $45 | 80.8% | -$45 | or Greater | 23.5% |
| + or - | $67 | 100.0% | -$22 | or Greater | 40.7% |

Without Joppa, there is over a 50% probability that profit margins from off-system sales will be within the range of ± $22 million, and over an 80% probability of being within a range of ± $45 million. Moreover, there is less than a 25% probability that AmerenUE faces a downside risk of profit margins dropping $45 million below the mean level that would be included in traditional rates.

In either instance, variability in profit margins from spot sales price risk is significantly mitigated by the correlation between fuel prices and spot-market prices. In order to determine whether a sharing mechanism is needed, the Missouri Commission should require AmerenUE to produce a similar type of study that also includes the variability from load and unit forced outages.

**Q. Did Mr. Schukar provide studies for variability in load?**

A. For the analysis of load, Mr. Schukar used the difference between budgeted net system load and actual, where the difference between these two represents variability due to both weather uncertainty and forecasting error. Based on this data from 1995 through 2005, Mr. Schukar determined that 2% variability in load is a reasonable upper bound on the increase in load over normal levels. Mr. Schukar then multiplies AmerenUE's normal load filed in this case by 2% to determine the increase in load that AmerenUE generation would have to meet in an extreme high load condition. So far, I follow Mr. Schukar's logic.

The final step of Mr. Schukar's analysis on load variability is to assume that if generation must meet this 2% increase in load, it would not be available to make off-system sales. If AmernUE were making off-system sales of at least 2% of its native load in every hour of the year and load increased by 2% in every hour of the year, then Mr. Schukar's assumption would be correct. However, the fact that AmerenUE does not make off-system sales in every hour of the year equal to at least 2% of its native load invalidates the assumption made by Mr. Schukar in his last step. In addition, since load variability due to weather may not be a uniform event throughout the year, AmerenUE needs to perform a detailed study of how seasonal loads and off-peak and on-peak loads vary with weather to determine what the impact would be on off-system sales. Finally, Mr. Schukar has not taken into account the fact that the energy component of rates paid by load include a portion of AmerenUE's fixed costs, and any increase in load sales provides AmerenUE with an increased profit margin from native load sales. This increase in profit margins from higher sales should also be included in order for the Missouri Commission to get a true picture of the financial impact on AmerenUE.

**Q. Did Mr. Schukar perform studies for variability in unit forced (unplanned) outages?**

A. For the analysis of unit forced outages Mr. Schukar analyzed data from 2000 through 2005 on unplanned outages. For each year, Mr. Schukar calculated the forced outage rates for AmerenUE's coal units. He determined that in 2003, when one of the Labadie units was down for 51% of the time, the coal fleet had a forced outage rate of 15.9% compared to the six-year average of 11.3%. This difference of 4.6% was determined by Mr. Schukar to be the amount of variability associated with forced outages and was multiplied by the capacity of the coal fleet to determine that the level of forced outages on the coal fleet could increase by 251 MWs per year. Mr. Schukar then multiplied 251 MWs per year by 8,760 hours per year to calculate energy (megawatt-hours) from the coal fleet that would not be available to make off-system sales.

As with his calculations for load variability, in order for these megawatt-hours to not be available for sales, one must assume that these additional outages would only occur in hours when AmerenUE is making sales, and that the outages would be no greater than the amount of sales being made. It is highly unlikely that this would be the case, and so Mr. Schukar's estimate of lost sales from outages is high. In order to correct this problem, AmerenUE needs to factor the forced outages into its production cost model on a random basis in order to determine the probable impact on off-system sales.

**Q. Place explain why it is highly unlikely that the additional outages calculated by Mr. Schukar would only occur in hours when AmerenUE is making sales, and that the outage would be no greater than the amount of sales being made?**

A. To get this level of increase in forced outages would require either one of the large coal units at Labadie, Rush Island or Sioux to be forced out of service for an extended period of time. These units range in size from 495 to 616 megawatts with an average size of 577 megawatts. Thus, over an extended period of time, AmerenUE's off-system sales would have to exceed these megawatt levels in every hour. While it is possible that this could happen during a portion of the hours in an extended time period, it is unlikely of this occurring in every hour over an extended period of time required to get the higher level of forced outages proposed by Mr. Schukar.

**<u>2. The Definition of Profit Margins from Off-System Sales Lacks the Specificity Required for the Proposed Sharing Mechanism to be Implemented in AmerenUE's Tariff</u>**

**Q. How does AmerenUE define and quantify profit margins from off-system sales in its filing in this case?**

A. At page 5 of Mr. Schukar's direct testimony he defines off-system sales margins as "gross off-system sales revenues minus the fuel costs associated with those revenues." At page 7 of Mr. Schukar's direct testimony he clarifies that the "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." At page 17 of Mr. Schukar's direct testimony he further clarifies that the coal and nuclear costs used to calculate the off-system sales margins are based on "fuel contracts with prices that will take effect as of January 2007."

**Q. Do you agree with Mr. Schukar's definition and quantification of profit margins from off-system sales?**

A. No, I do not. In discussions with AmerenUE's witness Mr. Timothy D. Finnell, the Staff determined that for purposes of this filing profit margins from off-system sales were determined by AmerenUE by running two separate production cost models, one with and one without off-system sales. Mr. Schukar is correct in stating that the fuel costs were determined using fuel contract prices, as these were applied to the two separate dispatches to calculate the incremental fuel costs for supplying off-system sales. However, on a day-to-day basis, production cost modeling is not used, and AmerenUE would have to specify what generation was used to meet its load requirements and what generation was used to meet its off-system sales. This means specifying the merit order in which the generation is dispatched, as lower incremental cost generation is first used to serve native load and higher incremental cost generation is then used for off-system sales. AmerenUE's testimony includes no specification of merit order or even a description of how AmerenUE would determine merit order for purposes of measuring profit margins from off-system sales. Thus, the Missouri Commission could be faced with a highly contentious issue regarding the calculation of the fuel costs involved in supplying off-system sales. Moreover, a complete specification of the calculation of profit margins should be required by the Missouri Commission for inclusion in the tariff. Even if that issue is resolved, there are other components to determining profit margins that were totally left out of the brief description included in Mr. Schukar's direct testimony.

**Q. What are the other components that Mr. Schukar failed to include in his calculation of profit margins from off-system sales?**

A. There is no discussion of whether variable operating and maintenance (O&M) costs that are not fuel related should also be included and how these costs would be calculated. Also, there is no indication that Midwest ISO costs related to AmerenUE's spot market activities would be included, yet many of these costs are directly related to the utility's degree of participation in the Midwest ISO spot-markets for electricity. For example, charges and revenues associated with Midwest ISO's Revenue Sufficiency Guarantee (RSG) should be included. If units are dispatched to make sales in the Midwest ISO's energy markets, they can receive additional revenues to cover start-up and must-run costs to the extent these are not covered by the market clearing price paid for the generation. The downside is that

AmerenUE also receives bills from the Midwest ISO to pay those same charges for others entitled to receive RSG revenues from the Midwest ISO. In addition, Mr. Schukar did not differentiate between profit margins earned in the Midwest ISO day-ahead market versus those earned in the Midwest ISO real-time market. For example, participants in the Midwest ISO real-time market can incur congestion costs, but there was no discussion as to how these charges would be treated in the sharing proposal. Also, in the day-ahead market, AmerenUE incurs congestion costs but also receives payments from its allocated Financial Transmission Rights (FTRs). Mr. Schukar has no discussion as to how these charges and revenues should be treated in the calculation of profits from off-system sales.

In summary, there is a lack of discussion in AmerenUE's filing as to how all of the Midwest ISO sources of revenues and costs related to spot market transactions would be included in the calculation of profit margins from off-system sales. This lack of discussion leads me to believe that AmerenUE is proposing not to include any of these additional elements, which will result in an overstatement of actual levels of profit margins from off-system sales.

**<u>3. The Proposed Base Level For Off-System Sales Margin Was Based on Rough Calculations Using Incomplete Information and Invalid Assumptions</u>**

**Q. What is AmerenUE's definition of "base level" for profit margins from off-system sales, and what does this base level represent?**

A. The first indication of what Mr. Schukar means by "base level" for profit margins from off-system sales is found on page 20, lines 12 through 16 of his direct testimony, where he states, "all off-system sales margins above the base level would be shared between AmerenUE and its customers." Then at lines 19 through 21 on that same page Mr. Schukar further states, "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. How did AmerenUE determine a base level for profit margins from off-system sales?**

A. Based on Mr. Schukar's direct testimony, it appears that the level of $120 million per year was selected based on his judgment. Specifically, Mr. Schukar's direct testimony at page 21, lines 6 through 10 states, "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." However, there is no reference to any studies performed by AmerenUE to confirm Mr. Schukar's belief.

While Mr. Schukar's testimony does not reference any study, when I submitted Staff Data Request No. 485, Mr. Schukar provided a spread sheet with the calculations that I previously described in this testimony as measuring the variability in sales related to variations in load and forced outage rates. Based on these rough calculations, Mr. Schukar estimates that off-system sales would be reduced by one third. Thus, moving from $180 million down to $120 million as a base level corresponds to a one-third reduction in profit margins from off-system sales. This estimate uses rough calculations with incomplete information and is based on assumptions that are not valid.

**Q. In your opinion, can a base level as defined by Mr. Schukar be used as the basis for a sharing mechanism without AmerenUE performing a specific study?**

A. As an expert witness I could not recommend a base level for profit margins from off-system sales without having a study to confirm my opinion. Moreover, if such a study was not performed, AmerenUE would choose a relatively low value to ensure that its "expert" opinion would not be wrong. However, this would not result in a level that the Missouri Commission should use in a sharing mechanism. Specifically, I recommend that the Missouri Commission reject AmerenUE's proposal on the ground of insufficient information to confirm a proper determination of a base level for AmerenUE's proposed sharing mechanism for profit margins from off-system sales. To be clear, I should note that if AmerenUE resolved this matter to the Staff's satisfaction, successfully addressing this item alone does not mean that the Staff would support a proposal for sharing profit margins from off-system sales.

**Q. What type of studies would you recommend be performed to determine a base level for profit margins from off-system sales?**

A. The study that I recommended earlier in my rebuttal testimony would provide an estimate of the probability distribution for profit margins from off-system sales. Based on this estimated probability distribution, the Missouri Commission could receive testimony on the appropriate level of probability to set for AmerenUE being unable to achieve a base level of profit margin from off-system sales.

**Q. For purposes of clarification, can you give an example of what you mean by a probability distribution for profit margins from off-system sales?**

A. Yes, the distributions shown on Schedule 2 are illustrations of the type of distributions that need to be developed before a determination of a base level can be made.

**Q. Based on your calculations, what would be the probability of AmerenUE not being able to achieve a profit margin from off-system sales of $120 million?**

A. Because of the lack of complete and valid information, at this time I am unsure of what probability would be assigned to a 33% decrease in profit margins. In AmerenUE's proposal, the mean is $180 million in profit margins, and the difference between the mean and what it calls the base level of $120 million is $60 million. This $60 million decrease as a percent of the mean is a decrease of 33%, which is beyond the extremes shown in the distributions on Schedule 2 of a decrease of approximately 25%. Keep in mind that the distributions shown on Schedule 2 do not include variations in load and unit forced outages, which emphasizes the need for AmerenUE to provide studies including the impact on variability of profit margins from off-system sales. Also keep in mind that a 25% decrease is an extreme that is beyond what should be set for a base level. For example, if Schedule 2 represented the full range of variability in profit margins, a decrease of 16.5% would represent a better lower bound for setting a base level for profit margins for off-system sales than 25%.

**<u>4. The Sharing Mechanism for Customers of 80% of Profit Margins Between AmerenUE's proposed Base Level up to its proposed "Normal" Level of Profit Margins and of 50% Between its "Normal" Level of Profit Margins up to twice that level is Arbitrary and Unfair.</u>**

**Q. What sharing mechanism did AmerenUE propose for profit margins between its proposed base level and its proposed normal level of profit margins?**

A. At page 21, lines 10 through 12 of his direct testimony, Mr. Schukar testifies that "until off-system sales margins reach $180 million, customers would share 80% of the margin above the $120 million threshold."

**Q. What is the purpose of this proposal to share 80% of the margin between $120 million and $180 million?**

A. The purpose for setting a sharing mechanism between base (AmerenUE estimates at $120 million) and normal (AmerenUE estimates at $180 million) levels of profit margins from off-system sales is to allow AmerenUE to increase customers' rates for any shortfall in profit margins it may experience below the normal level (down to the base level). Thus, under traditional ratemaking, the range from $120 million up to $180 million represents a **downside risk** to AmerenUE shareholders because if rates are fixed at a level based on normal profit margins and actual profit margins are below normal levels, the difference represents a lower rate of return on equity to AmerenUE, assuming all other revenues and expenses stay the same. In effect, the sharing proposal mitigates the downside risk of lower than normal profit margins from off-system sales by shifting this downside risk from shareholders to customers through higher rates. This is to the benefit of AmerenUE shareholders, but is also a detriment to AmerenUE customers.

**Q. Do you support AmerenUE's proposed 80% sharing mechanism for profit margins between the base and normal levels?**

A. No, I do not. In essence, if the Missouri Commission were to adopt the AmerenUE proposal it would penalize customers when AmerenUE actually earns its proposed normal profit margins from off-system sales. In this circumstance, customers would only get credit for $168 million in profit margins rather than the full $180 million. Note that the $168 million is calculated as $120 million plus 80% of the difference between the base level and normal level for profit margins ($60 million = $180 million - $120 million). Thus, not only would customers face higher rates for profit margins below the normal level, under

AmerenUE's proposal, they would also face higher than normal rates of $12 million even when AmerenUE's profit margins are equal to normal levels. This proposal is both arbitrary (no basis given for the 80% sharing level) and unfair (adding higher than normal rates when profit margins from off-system sales are normal). Instead, AmerenUE should be providing customers with a reward for allowing it to apply a rate increase in order to mitigate its downside risk.

**Q. Does Ameren's proposal then reward customers when profit margins from off-system sales are higher than normal?**

A. Yes, AmerenUE's proposal does reward customers when profit margins are higher than normal. When profit margins from off-system sales are higher than normal, AmerenUE proposes to allow customers to share in only 50% of the profit margins. However, this is arbitrary (there is no basis for the 50% sharing mechanism given) and it is possibly unfair (if it does not fairly compensate customers for bearing a portion of the downside risk).

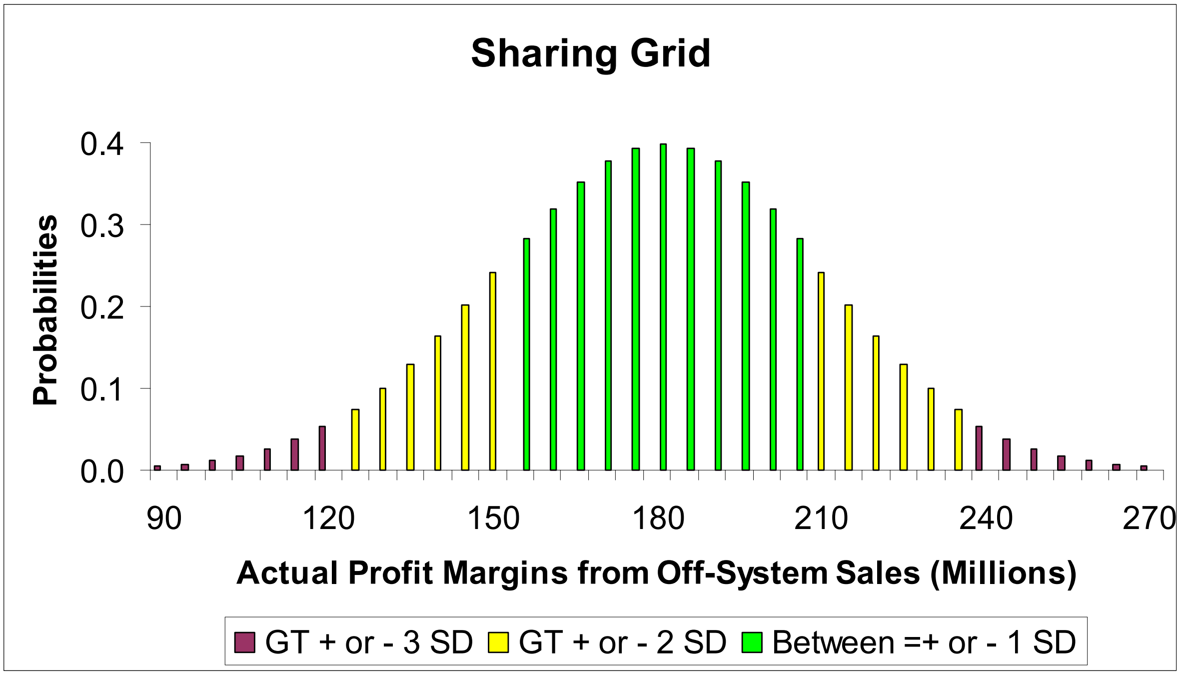
When profit margins from off-system sales are higher than normal, under traditional ratemaking this represents an **upside reward** to shareholders; i.e., an opportunity for AmerenUE to earn more than its normal rate of return on equity authorized by the Missouri Commission. While AmerenUE proposes to give up some of this upside reward by allowing customers to potentially receive lower rates when profit margins are higher than normal levels, the sharing proposal makes no mention of using the payment of a portion of the upside reward to customers as a method to provide a fair balance for the transfer of the downside risk to those same customers.

**Q. How do you ensure there is a fair balance between sharing downside risks and sharing upside rewards for customers?**

A. In order to provide this balance, the design of the sharing mechanism should result in an expected value equal to the normal profits determined appropriate and allowed by the Missouri Commission in this case. There is no assurance that this will be the case for the sharing mechanism being proposed by AmerenUE.

**Q. Can you give an example of a sharing mechanism that would reward customers for allowing AmerenUE to increase its rates to mitigate the risk of lower than normal profit margins from off-system sales?**

A. Yes. A properly designed sharing proposal that rewards customers for allowing rates to increase with lower than normal profit margins from off-system sales would allow rates to decrease with higher than normal profit margins from off-system sales, and would allow this to occur in a symmetric fashion. One way to do this is to put into place a band centered on normal profit levels. Within that band, if profits decrease, customer rates increase to compensate AmerenUE's shareholders, and when profits increase, rates decrease to compensate AmerenUE's customers. Below that band, AmerenUE would not be able to fully recover its short fall, and above that band, customers would not be able to benefit from decreased rates to fully reflect the excess. This is illustrated in the following graph for a symmetric distribution of profits, where the probabilities above and below the mean are proportional to their differences from the mean.




This graphic represents the following type of sharing that should be built into a properly constructed sharing grid:

| Sharing % | Sharing Grid Boundaries | % of Cumulative Probability |
|---|---|---|
| 100% | Less Than ± 1 Standard Deviations | 68.26% |
| 50% | Greater Than ± 1 Standard Deviations and Less Than ± 2 Standard Deviations | 27.20% |
| 0% | Greater Than ± 3 Standard Deviation | 4.54% |

The middle region of the graph where there is 100% sharing represent the area between ± 1 standard deviations (SDs). In this region 100% of any profit margins falling below the mean but above 1 SD will be passed on to consumers through a rate increase, and 100% of any profit margins above the mean but below 1 SD will be passed on to consumers through a rate decrease. The expected share in this range is equal to the normal profit level (shown as $180 million in the graph), and the probability of the downside risk (1 SD below the mean) is equal to the probability of the upside reward (1 SD above the mean). This represents 68.26% of the cumulative probability, and implies that 68.26% of the time profit margins from off-system sales will fall within this region.

The adjacent region of the graph where there is 50% sharing represents the area greater than ± 1 SDs but less than ± 2 SDs, and represents 27.2% of the cumulative probability distribution. As with the central region, the expected value of this region is equal to the normal profit level and the probabilities for downside risk and upside reward are equal. The most extreme region of the graph, where there is 0% sharing, represents the area greater than ± 3 standard deviations, and only accounts for 4.54% of the cumulative probability distribution.

A more refined sharing grid can be constructed, but this example illustrates the form that a sharing grid should take that properly balances shareholder and customer sharing of risk.

**Q. What are the design principles you applied to construct this example?**

A. There are two basic design principles that should be maintained for any sharing grid. First the expected value of the sharing should be equal to the normal level for profit margins. Second the probability of the downside risk or detriment should be equal to the probability of the upside reward or benefit. The first design principle requires the sharing grid to leave the shareholder and the customer in the same position as traditional ratemaking under repeated applications of the sharing grid. The second design principle balances the probability of the downside risk or detriment that is being shifted to customers with the probability of the upside reward or benefit being used to compensate customers for taking on the downside risk or detriment.

The use of 100% sharing in the center range is not necessary. For example, the sharing within this range could be 80%, but the application must balance the sharing of profit margins above and below the normal profit level. Otherwise the expected value for customers will not be equal to the normal profit level.

**Q. Does the sharing grid proposed by AmerenUE meet these principles?**

A. Without having the probabilities associated with the distribution of profit margins, there is no way of determining whether or not the sharing grid proposed by AmerenUE meets these principles. This is another reason that it is critical for the Missouri Commission to require AmerenUE to perform the type of study that I have previously recommended in this testimony.

**5. A sharing mechanism for profit margins from off-system sales contributes to AmerenUE's downside risk related to fuel expense.**

**Q. What is the interaction between variability in fuel expense and variability in profit margins from off-system sales?**

A. Based on the extreme price scenarios that were presented earlier in my rebuttal testimony, I calculated the impact on fuel expense both with and without profit margins from off system sales included. For purposes of this discussion, fuel cost minus revenues from off-system sales is called "net fuel cost," while fuel cost before subtracting out revenues from off-system sales is called "gross fuel cost."

The following table shows the downside fuel cost risk with and without the revenues from off-system sales for the case with Joppa, but does not include any downside risk for nuclear fuel.

**Net Fuel Cost Variability: With Joppa**

| Downside Risk With Sales | | Downside Risk Without Sales | | **Difference** |
|---|---|---|---|---|
| Millions | Prob | Millions | Prob | **Millions** |
| -$21 or Greater | 9.6% | -$112 or Greater | 9.6% | **-$91** |
| -$14 or Greater | 23.5% | -$75 or Greater | 23.5% | **-$60** |
| -$7 or Greater | 40.7% | -$37 or Greater | 40.7% | **-$30** |

With Joppa, if revenues from off-system sales are included, there is very little downside risk to AmerenUE from variability in fuel costs related to coal and natural gas. With off-system sales, the increased profits from off-system sales are used to mitigate the higher cost of fuel. That level of mitigation is significant. For example, without sales, fuel risk is $75 million or greater with a probability of 23.5%. This risk is reduced to $14 million or greater when profits from off-system sales are included. In addition, the "greater" portion for the without sales of $112 million is reduced to $21 million when profits from off-system sales are allowed to mitigate fuel price increases.

For purposes of comparison to AmerenUE's case, I have also included the case without Joppa.

**Net Fuel Cost Variability: Without Joppa**

| Downside Risk With Sales | | Downside Risk Without Sales | | **Difference** |
|---|---|---|---|---|
| Millions | Prob | Millions | Prob | **Millions** |
| -$59 or Greater | 9.6% | -$126 or Greater | 9.6% | **-$67** |
| -$39 or Greater | 23.5% | -$84 or Greater | 23.5% | **-$45** |
| -$20 or Greater | 40.7% | -$42 or Greater | 40.7% | **-$22** |

Without Joppa, there is less than a 25% probability that AmerenUE's fuel risk will exceed $39 million per year. If revenues from off-system sales are not included, this risk increases to $84 million per year (an increase of $45 million per year). While the risk levels for fuel costs are higher for the case without Joppa, the impact of not including revenues from off-system sales significantly increases AmerenUE's downside risk from fuel costs. When revenues from off-system sales are allowed to offset fuel costs, the downside risk to AmerenUE is significantly reduced, perhaps to a level that brings into question AmerenUE's need for a fuel adjustment clause. Staff witness Warren Wood will present rebuttal testimony on AmerenUE's need for a fuel adjustment clause.

**Q. Why does including revenues from off-system sales have such an impact on mitigating fuel cost variability?**

A. When fuel prices for coal and natural gas increase, the result is that spot market prices for electricity also increase. Thus, revenues from sales increase and tend to offset any large negative impacts from higher fuel costs.

What this implies is that if the Missouri Commission were to approve a sharing mechanism for off-system sales, the result would be to significantly increase AmerenUE's downside risk from increases in fuel costs. If the Missouri Commission also approves a fuel adjustment clause, what it would end up doing is lowering rates from the sharing mechanism for profit margins from off-system sales and raising rates from the increase in fuel expense. Instead, the Missouri Commission should look at these components in combination to see if profit margins from off-system sales are large enough to offset a need for a fuel adjustment clause.

**Q. Based on your analysis of the impact of sharing mechanisms on downside risk for fuel costs, what do you recommend to the Missouri Commission regarding the sharing of profit margins from off-system sales?**

A. Based on the results from the analysis I have been able to perform, at this time I cannot recommend that any type of sharing mechanism for profits from off-system sales be approved by the Missouri Commission. Moreover, it would be poor public policy to approve a sharing mechanism knowing that such a mechanism would cause AmerenUE to face greater downside risk with respect to fuel costs.

**B. REBUTTAL TO AMERENUE's ESTIMATES OF FUEL DISPATCH PRICES**

**1. AmerenUE's estimates of normal levels for fuel dispatch prices are too low and do not represent trends through 2005 for even their adjusted data, and are not representative of current levels for twelve month moving average price levels for either coal or natural gas.**

**Q. How did AmerenUE estimate normal levels for fuel dispatch prices used in its production cost model?**

A. For both coal and natural gas prices, AmerenUE based its estimates on a historical three-year average (2003 through 2005) after making adjustments for higher prices experienced during the last half of 2005.

**Q. Does your rebuttal testimony deal with the calculations performed by AmerenUE in developing its estimates of these normal prices?**

A. No, it does not. The Staff found several calculation errors in AmerenUE's work papers, but we have informed AmerenUE of these errors, and it has agreed that these errors should be corrected.

**Q. What then is the basis for your rebuttal of AmerenUE's estimated level for normal prices for coal and natural gas used for dispatching in its production cost model?**

A. A three-year average from 2003 through 2005 is not representative of the fuel prices that AmerenUE is facing today or is likely to face when rates go into effect. Moreover, with respect to coal prices, we already know that in January of 2007, new coal contract prices, which are consistent with current spot market prices for coal, are significantly higher than the three-year average used by AmerenUE in its production cost model. In essence, AmerenUE's production cost run combines an out-of-date historical average with an up-to-date calculation of fuel expense. This combination of "oranges and apples" is what caused me to question AmerenUE's use of a three-year average for coal dispatch prices.

**Q. Doesn't the Staff use multiple year averages to determine normal levels for some components of AmerenUE's costs?**

A. Yes, but averages must also be adjusted for known and measurable changes. When I compared the three-year average price for mine mouth coal to the prices in effect prior to March 2005, it simply did not make any sense to go back beyond March 2005 and use old data to calculate a normal for the current time period. From March 2004 through February 2005, the average mine mouth coal price at the four AmerenUE plant locations was ** _____________ **, compared to a current contract price of ** _____________ **. Thus, the current contract price is more than 27% higher than in the year just prior to March 2005. Since the current contract price for coal is consistent with current spot-market prices for coal, it makes little sense to estimate normal price to be significantly lower.

I should also point out that historical averages adjusted for known and measurable changes are extremely valuable in the determination of normal levels for a rate case. In this particular instance, I found AmerenUE's monthly distribution of prices based on its calculation of a three-year average to be a good estimate of the cyclical behavior of spot market prices. On the other hand, I found AmerenUE's monthly distribution of coal and natural gas prices to not be representative of normal prices.

**Q. Specifically, what did you find when you reviewed the monthly distribution of coal and natural gas prices?**

A. The monthly distribution for coal dispatch prices simply reflects the upward trend that historically has occurred with those prices. It does not represent any type of cyclical price behavior. The monthly distribution for natural gas prices used by AmerenUE is relatively flat except for random deviations that occurred in the months of March (high price) and September (low price), but does not represent any recognizable pattern of cyclical price behavior. Both of these monthly average profiles used by AmerenUE are shown on Schedule 3 attached to my rebuttal testimony.

**Q. Did you perform an analysis of the trends in coal and natural gas prices that included the AmerenUE adjustments for 2005?**

A. Yes. For purposes of comparison to normal levels, I performed a trend analysis for both coal dispatch prices and natural gas dispatch prices. These trends are shown on Schedules 4.1 and 4.2, where they are compared on a 12 month moving average basis to AmerenUE's adjusted data, its unadjusted data, AmerenUE's normal (three-year average) and Staff's normal.

**Q. Why did you perform your trend analysis using twelve-month moving average data?**

A. The objective is to determine average annual prices that are normal. Moreover, monthly price variation is a separate issue. Using twelve-month moving averages smoothes out the month-to-month behavior and allows the analysis to focus on trends in annual average behavior. Thus, twelve-month moving averages are the most appropriate data to use when analyzing trends in annual average prices.

**Q. Based on this analysis of the trends in coal and natural gas prices that included the AmerenUE adjustments for 2005, what did you discover?**

A. As would be expected, when there is an upward trend in prices (even after including AmerenUE's adjustments), a three-year average over this trend will not be normal for a current time period. Of course, trends can change and that is why I have included unadjusted data through the most current data available at the time I performed the analysis for determining the Staff normals.

For both coal and natural gas dispatch prices, AmerenUE's normal levels are too low to be reflective of the trends that exist even in the adjusted data, and are not reflective of current prices. On the other hand, the Staff's normal prices are much more reflective of these trends and current prices, and give a much better representation of normal levels for these inputs to the production cost model. Because normal price levels should reflect what the electric utility is likely to face when rates go into effect, the Missouri Commission should reject AmerenUE's normal levels for coal and natural gas dispatch prices and accept those proposed by the Staff.

**2. AmerenUE's estimates of normal levels for spot-market electricity prices are too low and do not represent trends through 2005 for even its adjusted data, and are not representative of current levels for twelve-month moving average price levels for either on-peak or off-peak prices.**

**Q. Did you perform a similar analysis of trends for on-peak and off-peak spot-market electricity prices?**

A. Yes, I did. The results of these analyses are shown on Schedules 5.1 and 5.2 attached to my rebuttal testimony.

**Q. What conclusions did you draw from the analysis of trends for spot-market electricity prices?**

A. As with the fuel prices, when there is an upward trend in spot-market electricity prices (even after including AmerenUE's adjustments), a three-year average over this trend will not be normal for a current time period. As with the analysis of fuel prices, I have included unadjusted data through the most current data available at the time I performed the analysis for determining the Staff normals.

For both on-peak and off-peak spot-market electricity prices, AmerenUE's normal levels are too low to be reflective of the trends that exist even in the adjusted data. On the other hand, the Staff's normal prices are reflective of these trends, and give a much better representation of normal levels for these inputs. Because normal price levels should reflect what the electric utility is likely to face when rates go into effect, the Missouri Commission should reject AmerenUE's normal levels for on-peak and off-peak spot-market electricity prices and accept those proposed by the Staff.

**3. When compared to contract coal prices used to calculate profit margins from off-system sales, AmerenUE's estimates of normal levels for coal and natural gas dispatch prices and spot-market electricity prices result in an abnormally low estimate for profit margins from off-system sales.**

**Q. Before presenting testimony explaining the low level for AmerenUE's estimate for profit margins from off-system sales, would you explain the difference between coal dispatch prices and contract coal prices?**

A. Yes. Probably the most significant difference between the two is the inclusion of an $SO_2$ cost component in the coal dispatch price. This same component is not included in the contract price for coal because AmerenUE has $SO_2$ emission allowances and does not need to purchase these at market price to serve its customers and make off-system sales. However, for purposes of dispatching generation, AmerenUE needs to look at the full market value of its incremental cost for making off-system sales. In essence, an alternative would be not to make the sale of energy to the spot-market for electricity and instead make the sale of the $SO_2$ allowance to the market for $SO_2$ allowances. Thus, the price for $SO_2$ allowances should be included in the coal dispatch price in order to properly calculate AmerenUE's opportunity cost for making off-system sales.

On the other hand, the Missouri Commission does not set rates based on opportunity costs; rather, it sets rates based on accounting costs. Since there is no accounting cost for the $SO_2$ allowances, these costs are not included in the calculation of fuel cost for the case.

**Q. Besides $SO_2$ costs, are there any other differences between coal dispatch prices and contract coal prices?**

A. AmerenUE uses spot-market coal prices to determine the mine-mouth component for coal dispatch prices. Depending on the contracts, over time these spot-market prices for coal can vary somewhat from contract prices.

**Q. What were the differences between coal dispatch prices and contract coal prices filed by the Staff and AmerenUE for this case?**

A. The following table shows the details for all four plant locations.

**Comparison of Coal Dispatch Prices to
Coal Contract Prices**

| | Staff Coal Dispatch Prices ¢/MMBTU | Staff Coal Contract Prices ¢/MMBTU | UE Coal Dispatch Prices ¢/MMBTU | UE Coal Contract Prices ¢/MMBTU |
|---|---|---|---|---|
| Labadie | ** ** | ** ** | ** ** | ** ** |
| Sioux | ** ** | ** ** | ** ** | ** ** |
| Rush Island | ** ** | ** ** | ** ** | ** ** |
| Meramec | ** ** | ** ** | ** ** | ** ** |
| **Average** | ** ** | ** ** | ** ** | ** ** |

Notice that while the Staff coal dispatch prices are higher than its coal contract prices, AmerenUE's coal dispatch prices are significantly lower than its coal contract prices. This occurred because AmerenUE is mixing historical average costs for dispatch with current costs for contract coal. This does not represent a normal situation, where the addition of associated

$SO_2$ emission allowance cost tends to make coal dispatch prices higher than contract coal prices.

**Q. When you ran the extreme case for low fuel (coal and natural gas) and low spot-market (off-peak and on-peak) prices, did the profit margins derived from this analysis reach the level of $180 million proposed by AmerenUE as normal?**

A. No, they did not. The lowest level of profit margins calculated were for the without Joppa case (comparable to AmerenUE's filing) at $204 million. This was the profit margin consistent with spot-market prices that were actually lower than those that AmerenUE used in its production cost runs as normal. The table below shows the on-peak and off-peak prices used in the Staff's Low case compared to those used in AmerenUE's "normal" case.

**Comparison of Staff Low Case to AmerenUE's Normal Case**

| Off-Peak Prices $/MWh | | On-Peak Prices $/MWh | | Profit Margin 1000 | |
|---|---|---|---|---|---|
| Staff Low | AmerenUE | Staff Low | AmerenUE | Staff Low | AmerenUE |
| $23.63 | $ 26.40 | $39.95 | $ 46.01 | $204,435 | $180,000 |

**Q. Why, when the Staff's low case has lower spot-market prices than in AmerenUE's "normal" case were there higher profit margins from off-system sales?**

A. A major problem with AmerenUE's "normal" case is that there is an inconsistency between coal dispatch prices and contract coal prices used to determine the accounting costs for the case. Moreover, AmerenUE used a three-year average price for coal dispatch costs and spot-market prices. While the dispatch prices are consistent with spot-market prices, they are significantly lower than the contract prices for coal (related to known and measurable contract changes starting January 2007). These significantly higher contract prices were applied by AmerenUE to determine the profit levels for off-system sales. The result of applying higher coal prices is to significantly reduce profit margins below normal levels.

In contrast, all of the Staff runs required a consistency between coal dispatch prices, spot-market prices and contract price for coal used to determine the profit levels from off-system sales. Moreover, when pricing out the production cost runs for both the low and high Staff cases, I instructed Staff witness Michael Rahrer to apply the same percentage increases to both coal dispatch prices and coal contract prices. This is because one should expect that while there may be some differences in these prices over time, they should be moving in the same direction.

**Q. What is the impact on the results of the production cost model from using low coal dispatch prices relative to contract prices for coal?**

A. To determine this impact, I calculated how much higher contract prices for coal would have to be above dispatch prices in the Staff's low case in order to push profit margins down from the Staff's level of $204 million to the AmerenUE level of $180 million. Clearly, contract coal cost would have to increase the incremental coal cost for off-system sales by the difference of $24 million. I calculated this to correspond to a 27.4% higher level for contract coal prices than used in the Staff's low case.

This 27.4% higher level for contract coal prices represents an extremely significant divergence between coal dispatch prices and contract coal prices, and is an aberration from normal rather than a normal situation for AmerenUE. Moreover, by combining a three-year average over the period 2003 through 2005 for spot-market prices and fuel dispatch prices with a known and measurable changes for contract coal prices for January 2007, AmerenUE has put together a scenario that has a very small probability of occurring. On this basis alone, the Missouri Commission should reject the AmerenUE filing as not being representative of normal market conditions.

## C. REBUTTAL TO AMERENUE's USE OF LIMITS FOR OFF-SYSTEM SALES

**Q. What megawatt per hour limits did AmerenUE place on off-system sales in its production cost model?**

A. The initial limits were set at 2,000 MW per hour for on-peak hours (including Saturday and Sunday) and 1,500 MW per hour for off-peak hours. In addition, AmerenUE adds an additional 500 MW per hour for one half of the hours on a random basis. Thus, on average, the limits are 2,250 MW per hour for on-peak hours and 1,750 MW per hour for off-peak hours.

**Q. How did AmerenUE determine these limits?**

A. The Staff requested this information in Staff D.R. No.146. It appears from the response prepared by Mr. Timothy Finnell that the limits were developed by looking at historical sales for the twelve-month period starting September 28, 2003 and ending on September 27, 2004. This data apparently was used to determine limits for the fuel budget process for 2005. These limits were set at 1,500 MW/hour for weekday on-peak, 1,200 MW/hour for weekend on-peak and 800 MW/hour for weekday off-peak. Subsequent to this analysis, Mr. Finnell adjusted these limits up to 1,750 MW/hour for on-peak and 1,250 MW/hour for off-peak in a calibration of the 2005 fuel model that was intended to take into account the impact of the Midwest ISO's energy markets that started up in March of 2005. Finally, Mr. Finnell added 500 MW/hour to the limits to reflect the elimination of the Joint Dispatch Agreement.

**Q. Do you agree with setting limits on off-system sales as a modeling technique to use in the estimation of production costs?**

A. No, I do not. First, limits on sales change hourly, and using annual limits like those designed by AmerenUE does not reflect the reality of a bid-based energy market like the day-ahead and real-time energy markets that are operated by the Midwest ISO. Second, when setting annual limits, AmerenUE did not look at the maximum level of sales that it was able to make in the historical period. Instead, it calibrated these limits to arrive at a level of generation that it experienced historically. In modeling for transmission systems that require physical transmission rights in order to make off-system sales, this calibration technique can be useful. However, the historical period does not provide a relevant basis for the time when rates go into effect because of the elimination of the Joint Dispatch Agreement. AmerenUE attempted to adjust for this by making a purely arbitrary addition of 500 MWs/hour to the limits it used to calibrate to the historical data.

**Q. With respect to limits on off-system sales, what is the reality of a bid-based energy market such as the Midwest ISO's day-ahead and real-time market?**

A. In a bid-based energy market, the Midwest ISO's objective is to meet the demand for electricity with the lowest possible supply bids from generators. In order to meet this objective, the Midwest ISO determines a market-clearing price for each generation and load location. Any generation bid above the market-clearing price is not eligible to be dispatched in the market and all generation that is bid below the market-clearing price is dispatched to meet demand. Thus, price is the mechanism used in a bid-based market to limit generation from a source when there are transmission constraints. For example, if a more expensive generation source downstream from a constraint needs to be substituted for a cheaper generation source upstream from a constraint, then the market-clearing price downstream will be increased to add more supply downstream and the market-clearing price upstream will be decreased to decrease supply upstream. Thus, it is the price levels set for off-system sales that should determine whether or not AmerenUE generation is dispatched.

In this respect it is important that the off-system prices match with loads and dispatch costs of the generators. If this matching is maintained, there is no reason to artificially add physical transmission limits to the production cost model.

**Q. Your testimony indicated that each generating unit faces an individualized price that reflects any congestion that is specific to that generator. Does either AmerenUE's production cost model or the Staff's production cost model provide an individualized price for each generation source?**

A. No, neither model was specifically designed to use different prices for each generation source. Instead, both models were designed using an average hourly price for off-system sales.

**Q. In your opinion, does moving to an average price for off-system sales result in some of the units possibly being over-dispatched and other units possibly being under-dispatched in the modeling of production costs an off-system sales?**

A. While this is a possibility in a given hour, over the entire year this would only occur when a subset of the units being dispatched in the model to make off-system sales face a much greater constraint than the other units being dispatched to make off-system sales. If this were the case, then AmerenUE should have differentiated between these two sets of units in determining off-system sales prices rather than setting overall limits on off-system sales.

**Q. With respect to estimating annual limits for off-system sales, what problems did you find with the initial estimates developed by AmerenUE?**

A. In the data analysis where AmerenUE used the September 28, 2003 to September 27, 2004 historical data to determine limits for off-system sales for the 2005 fuel budget, I noticed that there were significant hours where the sales data exceeded the limits that were set. For the off-peak hours, the actual sales data exceeded AmerenUE's design limit for 739 hours at an average of 328 MWs over the 800 MW design limit. For the on-peak weekend hours, the actual sales data exceeded AmerenUE's design limit for 397 hours at an average of 302 MW over the 1,200 MW design limit. For the on-peak weekday hours, the actual sales data exceeded AmerenUE's design limit for 463 hours at an average of 248 MW over the 1,500 MW design limit. In addition, I found that in 306 of these hours, actual sales exceed AmerenUE's design limits by 500 MWs or more, and for 39 hours, actual sales exceeded limits by 1,000 MWs or more. Based on these results, I find AmerenUE's original design limits to be overly conservative. Moreover, I can understand having something in the range of 100 to 200 hours where limits were exceeded, but to exceed limits by averages of from 248 to 328 MW for almost 1,600 hours makes the initial determination of these design limits difficult to accept as reasonable.

**Q. Have you estimated what the limits should be to bring the total number of hours where limits are exceeded to a reasonable level?**

A. For the September 28, 2003 to September 27, 2004 data, setting limits of 1,550 MW per hour for off-peak, 2,000 MW per hour for on-peak weekdays and 1,700 MW per hour for on-peak weekends would bring the total hours for which these limits are exceeded down to 199 hours.

**Q. Are these limits close to those that AmerenUE determined were reasonable to set for 2005 with the Midwest ISO market in place but still including the Joint Dispatch Agreement?**

A. Yes, the limits that AmerenUE determined by calibrating to its 2005 generation from January through November were actually split between the periods January through September and October through November. AmerenUE provided no explanation as to why at this step of its analysis it had developed two sets of limits. However, since the October through November limits were set lower than the January through September limits, AmerenUE must have determined that the higher limits allowed too many sales in the October through November time period. The following table shows the limits determined in AmerenUE's 2005 calibration.

**AmerenUE's 2005 Calibration of Limits to Off-System Sales**

| | Weekdays On-Peak | Weekends On-Peak | All Days Off-peak |
|---|---|---|---|
| Jan-Sep | 2,250 | 2,250 | 1,750 |
| Oct-Nov | 1,750 | 1,750 | 1,250 |

AmerenUE apparently made no calculations of how these limits compared to actual sales for the same period. This type of information should have been critical to the determination of the validity of these limits. Instead, Mr. Finnell simply states that, "The 2005 calibration run was used to adjust the sales volumes from the previous step. The adjustments were done to update the data for the impact of the MISO Day 2 market." However, it appears to me that these limits are consistent with the limits that should have been set from the September 28, 2003 through September 27, 2004 data; a period well before the start-up of the Midwest ISO energy markets ("Day 2 market") that occurred in March of 2005.

**Q. Do you agree with the final step taken by AmerenUE to add 500 megawatts to the limits set for 2005 in order to reflect the elimination of the Joint Dispatch Agreement?**

A. No, I do not. Mr. Finnell provided no evidence to support the addition of only 500 MW. As a matter of fact, while Mr. Finnell did add 500 MW to the lower values that he determined for September through October of 2005, there were zero megawatts added to the January through September limits determined for 2005 calibration. Thus, it appears that much fewer than 500 MW per hour were added for the Joint Dispatch Agreement.

I simply do not understand the reasoning behind these numbers. No data regarding transfers of MWs from AmerenUE to Ameren Energy Generation to serve Ameren CIPS loads were analyzed. Thus, we have no real indication of what off-system sales from AmerenUE could potentially be for the case without the Joint Dispatch Agreement.

**Q. Would you summarize your rebuttal of AmerenUE's determination and use of limits for off-system sales in its production cost model?**

A. Yes. The initial values estimated by AmerenUE as limits for the historical period September 28, 2003 through September 27, 2004 were too low. The calibration for 2005 to add to these limits for the start-up of the Midwest ISO Day 2 energy markets failed to include any analysis of actual sales data compared to limits that appear to be consistent with historical sales from a period prior to the start of the market. The so-called addition of 500 MW for the elimination of the Joint Dispatch Agreement failed to compare limits to actual sales plus transfers from AmerenUE to AmerenCIPS that occurred in 2005. In summary, I find little reason to believe that the limits used by AmerenUE are reasonable, and would recommend against the use of such limits in modeling the Midwest ISO market. Moreover, the Commission should depend on the correlation of off-system (spot-market) prices to loads and to corresponding dispatch costs to limit the sales in the production cost model.

**Q. Does this complete your rebuttal testimony?**

A. Yes, it does.

# Schedules 1.1, 1.2 and 1.3

# Are Deemed

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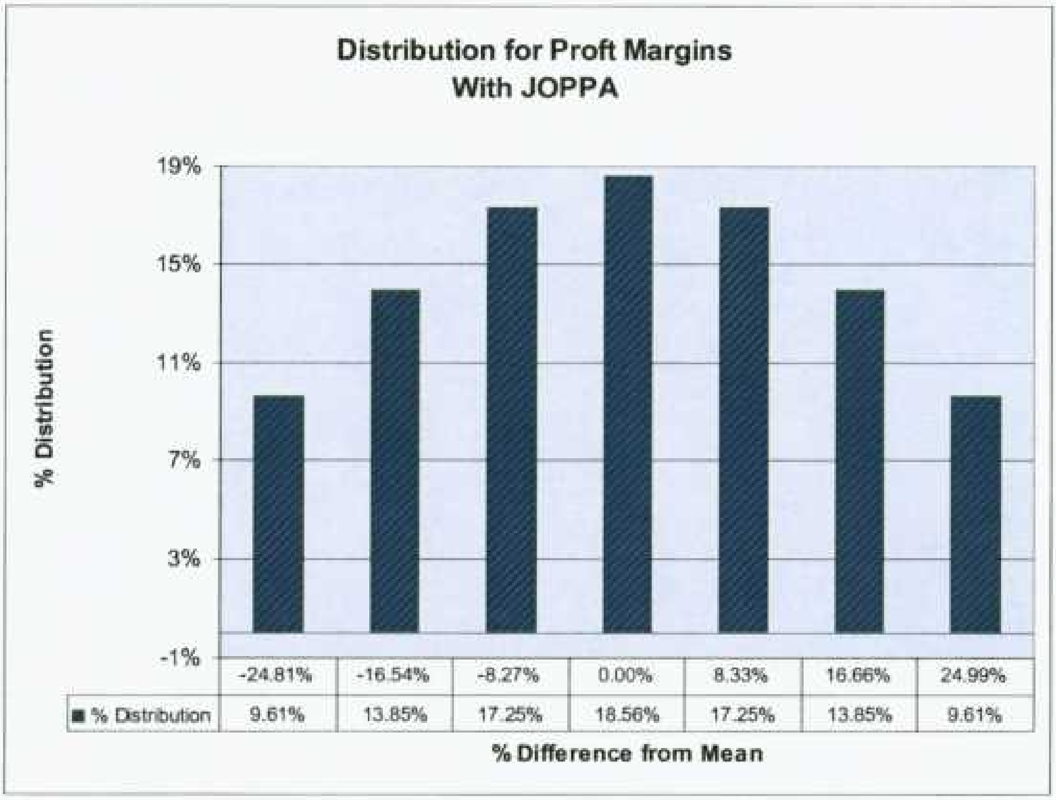
# In Their Entirety


Distribution for Proft Margins
With JOPPA
19%
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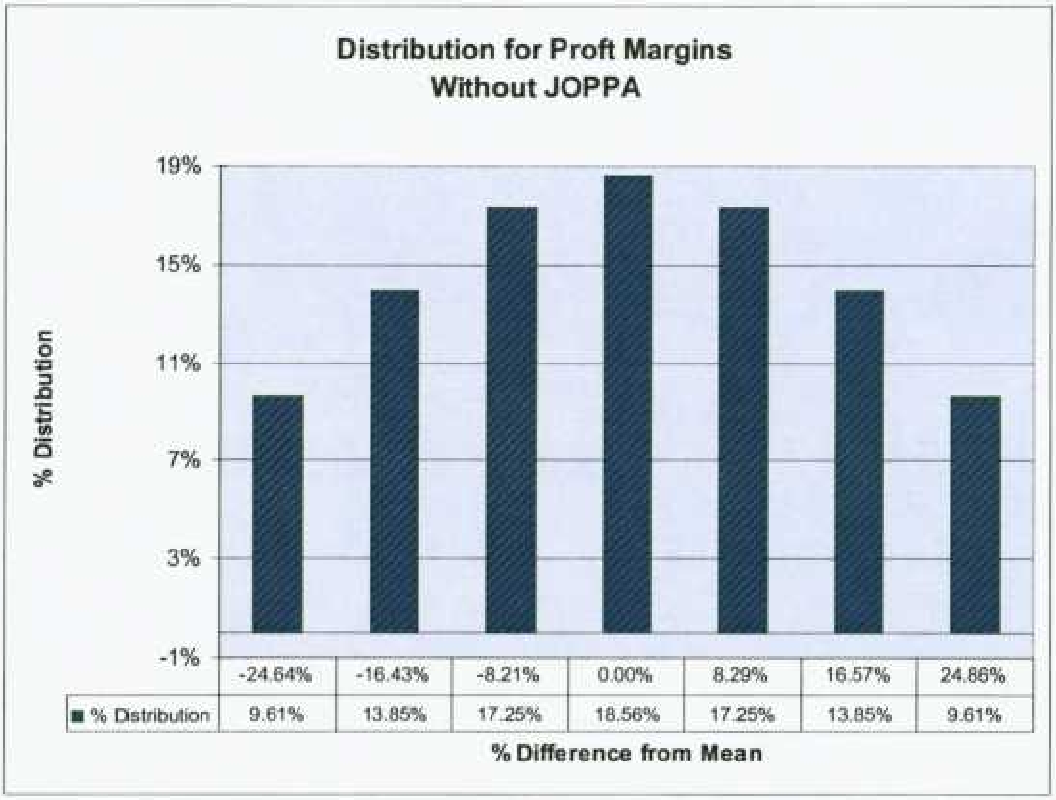
Distribution for Proft Margins
Without JOPPA
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# Schedule 3

# Is Deemed

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# In Its Entirety

# Schedules 4.1 & 4.2

# Are Deemed

# Highly Confidential

# In Their Entirety

# Schedules 5.1 & 5.2

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