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Issues:	Volatility and Uncertainty of Net Fuel Costs
Witness:	Ajay K. Arora
Sponsoring Party:	Union Electric Company
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2008-____

DIRECT TESTIMONY

OF

AJAY K. ARORA

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

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

St. Louis, Missouri
April, 2008

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TABLE OF CONTENTS

DIRECT TESTIMONY

OF

AJAY K. ARORA

CASE NO. ER-2008-____

I. INTRODUCTION

Q. Please state your name and business address.

A. Ajay K. Arora, Ameren Services Company ("Ameren Services"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Services and what are the responsibilities of your position?

A. I am the Director of Corporate Planning at Ameren Services. Ameren Services provides corporate, administrative and technical support for Ameren Corporation and its affiliates. In my current position I oversee the Quantitative Analysis, Asset and Trading Optimization, Integrated Resource Planning, Load Analysis, and Operations Analysis groups within the Corporate Planning function at Ameren Services. I also work on analysis for specific corporate strategic initiatives as required.

Q. Please describe your educational background and work experience.

A. I received my Bachelor of Science Degree in Chemical Engineering from the Panjab University (India) in May 1992. I received my Master of Business Administration degree from Tulane University in May 1998. I joined Ameren Energy in June, 1998 and held trading and structuring positions in Ameren Energy before supervising the group that prices structured energy products for Ameren Energy Marketing Company's wholesale and retail customers from 2002 to 2004. From 2004 to 2007 I was responsible for the analytical group supporting AmerenUE's transition into the Midwest Independent Transmission System Operator, Inc. ("MISO"), including reviewing specific market design issues in MISO. In 2007 I led the AmerenUE Regional Transmission Organization cost-benefit study that was filed with the Commission in Case No. EO-2008-0134, and I assumed responsibility for the Quantitative Analysis, Integrated Resource Planning, Load Analysis, and Operations Analysis groups. In January 2008, as part of my current role as Director of Corporate Planning, I assumed the additional responsibility for the Asset and Trading Optimization group supporting AmerenUE trading and asset optimization.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is to document the uncertainty of AmerenUE's net fuel costs which, in turn, provides support for one of the bases addressed by AmerenUE witness Martin J. Lyons, Jr. in his direct testimony relating to AmerenUE's request to implement a fuel adjustment clause ("FAC"). Net fuel costs are the Company's fuel, fuel transportation, and purchased power costs, net of off-system sales revenues.

An Executive Summary of my testimony is attached hereto as Attachment A.

III. ANALYSIS OF UNCERTAINTY OF NET FUEL COSTS

Q. How was the uncertainty of net fuel costs determined?

A. A probabilistic production cost model, RTSim, was used to calculate the uncertainty around net fuel costs. RTSim is described as a "probabilistic" production cost model because it uses statistical distributions rather than fixed values for model inputs, such as market prices for off-system power sales, fuel costs, generating unit availability, and loads. The output of the RTSim model is a range of net fuel costs for the period being analyzed, where net fuel costs include fuel costs, the variable component of purchased power and revenues from off-system sales.

Q. Could the PROSYM model discussed in the direct testimony of AmerenUE witness Timothy D. Finnell have been used to show the uncertainty of net fuel costs?

A. Yes, but PROSYM would need to be adapted to show the uncertainty around net fuel costs. As I noted, RTSim, because of its probabilistic inputs, is designed to measure uncertainty, thus it is better suited to measure uncertainty around net fuel cost.

Q. Please elaborate on the comparison of the RTSim and PROSYM models.

A. RTSim is a chronological hourly production cost model similar to PROSYM that uses loads, fuel costs, market prices, plant availabilities, plant operating characteristics and system requirements to calculate net fuel costs. The RTSim model is different from PROSYM because it uses statistical distributions for the key inputs and performs a large number of iterations which result in a range of net fuel costs rather than a single value for net fuel costs.

Q. Do other utilities use the RTSim model?

A. Yes. There are currently eleven utilities that use RTSim to analyze financial risks. Some utilities use the RTSim model to evaluate their power trading strategy and others use the model to evaluate their natural gas positions.

Q. How long has Ameren Services been using RTSim?

A. Ameren Services began using the RTSim model in 2000.

Q. How has the RTSim model been used by Ameren Services?

A. The principal use of the RTSim model has been to perform risk analyses, such as setting trading limits for off-system sales. Other uses of RTSim have included evaluating the effectiveness of hedge plans for off-system sales, and evaluating planned outages for the major generating units.

Q. How is the RTSim model being used in this case?

A. The RTSim model is being used to compute the uncertainty for two different time periods. First, RTSim was used to model uncertainty existing at the beginning of the test year, considering AmerenUE's substantially hedged fuel positions as of that time. Second, RTSim was used to model the combined uncertainty that can be expected during the years 2009 through 2012, considering AmerenUE's hedged (or known) positions with respect to fuel, purchased power, and off-system sales as of February 2008. The RTSim analysis calculates the impact on AmerenUE's net fuel costs using the uncertainty in several relevant variables: power prices, fuel costs, unit outages, native load and off-system sales quantities. The uncertainty parameters are based on historical data. The RTSim model also incorporates relevant operational data such as the use of spot natural gas prices rather than long-term natural gas prices and correlations between variables, such as temperatures and power prices.

For each uncertain variable, a measure of the average annual dispersion around the base forecast for that variable was computed (which I refer to as the "annual uncertainty factor," described further below). In addition, correlation measures of how the uncertainty in each variable is related to the uncertainty in the other variables were estimated. Using these uncertainty parameters, 250 scenarios of joint outcomes for the uncertain variables were developed that reflected the dispersion and the estimated correlations between the variables. RTSim was run to compute AmerenUE's net fuel cost for each of the 250 input scenarios. The dispersion of the 250 RTSim computations of AmerenUE's net fuel cost demonstrates the uncertainty in AmerenUE's net fuel costs.

To illustrate the risk mitigation achieved by the Company's hedging and long-term contracting efforts, the uncertainty in net fuel costs that the Company faced at the beginning of the test year was modeled, considering the "typical" hedge ratios at the beginning of a year and the uncertainty parameters developed for this simulation. We also modeled uncertainty for future years (2009 – 2012) using hedge ratios as of February 2008. These uncertainties were then applied to "targets" (that is, the average anticipated values) for each of the uncertain variables. The combination of these "targets" and uncertainty parameters, including correlations between key variables, results in an average level of annual net fuel costs and an uncertainty range around that average value.

A. Development of Target Levels and Uncertainty Distributions

Q. How were the power market price inputs developed for RTSim?

A. The market prices for power were developed in two steps. The first step was to calculate the market price uncertainty; the second step was to determine a target market price.

The market price uncertainty was developed from historical hourly MISO Locational Marginal Price ("LMP") data for the Day Ahead Cinergy Hub (located in the MISO's footprint) for the period January 2006 through December 2007. The Day Ahead prices were used because most of AmerenUE's off-system sales are made in the Day Ahead ("DA") market rather than the Real Time ("RT") market (during 2007, **[redacted]** of the off-system sales were sold in the DA market and **[redacted]** of the off-system sales were sold

NP

in the RT market). Cinergy Hub prices were selected over prices at other LMPs because the Cinergy Hub is a recognized hub that is frequently used for power trading in the MISO market.

The market price uncertainty is the standard deviation of the market prices for various time periods.[1] Four pricing periods were modeled for each month, corresponding to four well-recognized pricing periods during which off-system sales may be made. These pricing periods are: weekdays on peak (Monday thorough Friday, hour ending 7 (7:00 a.m.) to hour ending 22 (10:00 p.m.)), often referred to as a 5 x 16 period; Saturday on peak (hour ending 7 to hour ending 22); Sunday on peak (hour ending 7 to hour ending 22); and Monday through Sunday off peak (hour ending 1 to 6 and hour ending 23 and 24), often referred to as a 7 x 8 period.

The standard deviation of the market prices was calculated in two steps. The first step was to calculate an average price for each day, for each price period, for each month. The second step was to calculate the standard deviation of the daily averages for each price period for each month. For example, the standard deviation for the January on peak market power prices was calculated using each daily weekday on peak price from January 2006 and January 2007. There were 21 weekdays in January 2006 and the daily on peak prices ranged from $38.37 per megawatt-hour ("MWh") to $66.68/MWh, and there were 22 weekdays in January 2007 and the daily on peak prices ranged from $35.58/MWh to $68.09/MWh. The standard deviation of all the daily weekday on peak prices from January 2006 and January 2007 was calculated to be $10.80/MWh.

The target market prices for each month of the test year were developed from actual AmerenUE generator LMP data from the period January 2006 through December

[1] The standard deviation is a measure of how widely values are dispersed from the average value.

2007. The target market prices for the four pricing periods for 2009 through 2012 were obtained from published forward prices from the time period January 2006 through December 2007 for delivery in the January 2009 through December 2012 period. The primary source for the daily forward price data for January 2009 through December 2012 was the average of several widely-used daily industry pricing publications: *ICE*, *Platt's MW Daily*, *ICAP*, and *Amerex*. In the event that market prices were not available for a specific pricing period, historical relationships were used to calculate the market price for the pricing period. For example, the 2012 market price quotes were available only as an annual price. The monthly prices and the time period prices were calculated using the 2006-2007 historical relationships of each pricing period to the annual price.

The market price uncertainty and the target power prices were used to create 250 sets of hourly prices for each year of the study period. Random draws were used to implement the market price uncertainty in each price period and the average of the 250 price periods in each month was constrained to equal the monthly target prices for that period.

Q. How did you determine if the 250 annual hourly price curves resulted in a reasonable representation of average annual prices and the average annual uncertainty in these prices?

A. The first step was to calculate the annual average Around The Clock ("ATC") price for each of the 250 iterations. The second step was to calculate the standard deviation of the average annual ATC prices for the 250 iterations. This standard deviation was then divided by the average annual ATC price to calculate the "annual uncertainty factor" I mentioned earlier. For example, the standard deviation of the annual average ATC price for the test year was $**[redacted]**/MWh, and the annual average ATC price for the test year was

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$**[redacted]**/MWh, which results in an annual uncertainty factor of **[redacted]**. Schedule AKA-E1 contains a table showing the annual uncertainty factor calculation for the ATC power prices for the test year and also for the period 2009 through 2012. This annual uncertainty factor was compared to the annual uncertainty factor developed from historical ATC power prices from 1999 to 2007. See Schedule AKA-E2. The 1999 to 2007 average annual ATC power prices had a standard deviation of $7.44/MWh and an average annual price of $33.80/MWh, which resulted in an actual annual uncertainty factor of 22%. The modeled annual uncertainty factor of 22% compares favorably to the historical annual uncertainty of **[redacted]**, shown on Schedule AKA-E1 as noted earlier, which confirms that the model reasonably represents average annual power price uncertainties.

Q. Above you addressed uncertainty in power prices. How did you develop the uncertainty parameters for other key inputs, notably the fuels used by AmerenUE's generation fleet?

A. I developed a separate price distribution for the three primary fuel types used by the AmerenUE generation fleet. The primary fuel types are coal, natural gas, and nuclear fuel.

Q. How did you model coal price uncertainty?

A. The delivered coal price has several components which include the coal commodity, base transportation costs, diesel surcharges related to the base transportation costs, railcar expenses, and dust suppression costs. The delivered coal price at the beginning of the test year assumes no uncertainty because AmerenUE generally has contracts in place for close to 100% of its coal needs, and had hedged[2] most of its exposure to the individual

[2] For the purpose of this analysis I have conservatively modeled "hedged" market prices as fixed-priced contracts, which will tend to understate uncertainty because hedging does not always mean that a fixed-priced

NP

components of delivered coal prices (i.e., commodity and transportation, including diesel fuel surcharge). For the period 2009-2012, delivered coal price uncertainty was modeled because not all of the coal and transportation components are currently under contract. The hedge ratios applied to those years are the actual hedge ratios in place for those years as of February 2008.

The delivered coal price uncertainty was developed from various delivered coal price components provided by AmerenUE witness Robert K. Neff, as well as historical published forward price data for specific delivered coal price components. Mr. Neff also provided information as to whether the delivered coal price components were under contract or not under contract. If the coal price component is under contract, the component is modeled as "hedged," if the coal price component is not under contract it is modeled as "un-hedged." Mr. Neff provided the price for each component when it was hedged. For the un-hedged delivered coal price component, which was not derived from already known contract pricing, Mr. Neff provided a low and a high price estimate that were used to develop an uncertainty distribution.

The level and uncertainty in commodity costs for the un-hedged Powder River Basin, Wyoming ("PRB") coal were developed using historical daily quotes of published annual forward coal prices for future delivery years. For example, the price distribution for 8800 Btu/lb. 0.8 #SO_2/MMBtu PRB coal, AmerenUE's largest coal type, was developed using historical daily forward price quotes for PRB coal from the period January 2006 through December 2007 for delivery in 2009 through 2012. Also, the target price for the coal

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outcome is achieved. For example, hedges for diesel fuel surcharges only place a cap on the price. Similarly, one of the long-term coal commodity and many of the coal transportation contracts are not fixed-priced contracts, but are inflated over time based on an inflation index that is currently unknown. These long-term contracts have also been modeled conservatively as fixed price contracts.

was obtained from the 2006 through 2007 average historical forward prices for 2009 through 2012. The forward annual PRB coal prices were obtained from *ICAP* and *Platt's Coal Daily*. Only annual prices were considered because AmerenUE's coal purchasing strategy is based on long-term coal contracts (one year or longer). The price distribution for the Illinois Basin coal used by AmerenUE was based on high and low cost estimates provided by Mr. Neff. Mr. Neff used a blend of prices for different Illinois coals because there is no standard Illinois coal suitable as a reference coal, such as 8,800 Btu/lb. PRB coal. The Illinois coal prices vary due to quality, mine location, and length of contract. The blended prices were calculated using prices from consultant studies, over-the-counter broker sheets, and recent bids.

A coal price uncertainty factor for the test year was not applied because the coal was almost completely hedged for that period. However, during the period 2009 through 2012 not all coal needs are hedged because new coal contracts with uncertain pricing will still need to be signed to meet projected coal burns. Thus an annual uncertainty factor was calculated for these years. The annual uncertainty factor was calculated for un-hedged 8,800 Btu/lb. PRB coal purchased in 2012. The standard deviation for the 8,800 PRB coal was $**[redacted]**/ton and the average price was $**[redacted]**/ton, which results in a simulated annual uncertainty factor of **[redacted]**. In comparison, the "annual uncertainty factor" developed using historical 8,800 Btu/lb. PRB coal prices from 1999 to 2007 was calculated to be 31%. See Schedule AKA-E2. This means the RTSim simulation likely understates the average annual uncertainty associated with 8,800 Btu/lb. PRB coal.

The cost uncertainty for the diesel fuel surcharge associated with the base transportation component of delivered fuel costs was also based on historical quotes of

NP

forward diesel fuel prices. The diesel fuel surcharge prices and associated uncertainties were calculated using historical forward price quotes for heating oil from the period January 2006 through December 2007 for delivery in 2009 through 2012.[3] The forward heating oil prices were obtained from the New York Mercantile Exchange ("NYMEX"), and basis adjusted to the On-Highway Diesel Rail Surcharge Index. The cost uncertainty for the other coal price components: base transportation, railcar expense and dust suppression were developed from low and high cost estimates provided by Mr. Neff.

The hedged and un-hedged coal component data was combined into 250 annual prices for each plant.

Q. How did you measure natural gas price uncertainty?

A. The natural gas uncertainty used in the model was developed using the actual daily natural gas prices for the period January 2006 through December 2007. The uncertainty measure is the standard deviation of the daily natural gas prices for each month during the period January 2006 through December 2007. The use of spot market natural gas prices versus monthly natural gas pricing is appropriate for AmerenUE natural gas generation because of the unpredictability of natural gas generation. The AmerenUE natural gas generation varies significantly due to load uncertainty, availability of other generating units, off-system sales market conditions, spot natural gas prices and MISO system requirements. For example, the AmerenUE combustion turbine generator ("CTG") fleet produced 409,769 net MWh in 2006 and production more than doubled to 889,560 net MWh in 2007. **[redacted]** net MWh of 2007 CTG generation were used for off-system sales. Some of

[3] The transportation agreements use On-Highway Diesel forward prices to determine the fuel surcharge. However, the On-Highway Diesel forward price product was not traded product until March 2008. AmerenUE has used heating oil call options to hedge exposure to diesel fuel surcharges because of the high correlation between heating oil and On Highway Diesel forward prices.

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this natural gas generation was used for off-system sales based only on economics, when the cost of the natural gas generation was less than the market clearing price, and the rest of the generation was used by MISO to support the reliability of MISO transmission system operations.

The natural gas price uncertainty is combined with target natural gas prices to develop 250 sets of natural gas prices for each year. The target natural gas prices for the test year simulation were the actual 2006-2007 natural gas prices. The 2009 through 2012 target natural gas prices were based on the NYMEX futures contracts quotes from the period January 2006 through December 2007 for delivery between January 2009 and December 2012.

As in the case of power and coal prices, to analyze whether these uncertainty parameters result in a simulated average annual uncertainty that is comparable to historically experienced uncertainty in average annual prices, we also calculated annual uncertainty factors. For example, at the beginning of the test year, the standard deviation of the natural gas price for the test year was $**[redacted]**/MMBtu, and the average natural gas price was $**[redacted]**/MMBtu, which results in a simulated "annual uncertainty factor" of **[redacted]**. See Schedule AKA-E1. In comparison, the annual uncertainty factor developed using historical natural gas prices from 1999 to 2007 was calculated to be 36%. See Schedule AKA-E2. This means the simulations will likely understate the average annual uncertainty associated with natural gas prices. However, because of the relatively small amount of natural gas generation used by AmerenUE currently as compared to total annual AmerenUE fleet generation, the use of a smaller, understated uncertainty factor is not expected to affect the overall magnitude of annual net fuel cost uncertainties.

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Q. How did you measure nuclear fuel price uncertainty?

A. The nuclear fuel price uncertainty was developed using data provided by AmerenUE witness Randall J. Irwin. The nuclear fuel data included a low, expected, and high price for each price component of nuclear fuel. The nuclear fuel cost components are: the uranium fuel itself, uranium conversion, uranium enrichment, and fabrication of nuclear fuel assemblies. The nuclear fuel data were converted into 250 price curves based on the price distributions provided by Mr. Irwin.

As described by Mr. Irwin, there is only very limited uncertainty with the nuclear fuel costs until 2012. The nuclear fuel costs are assumed to be fully known at the beginning of the test year since the fuel is already in the reactor. The nuclear fuel annual uncertainty factor ranges from less than **[redacted]** in 2009 up to **[redacted]** in 2012. See Schedule AKA-E3.

Q. How was the generating unit availability uncertainty modeled?

A. Generating unit availability is comprised of two types of generating unit outages, planned and unplanned outages. Planned outages are placed in a specific time period and are not changed in each RTSim iteration. The unplanned outages include short-term outages when the unit is completely out of service and periods when the unit cannot reach full capability due to the equipment limitations (i.e. derates). RTSim develops 250 random patterns of unplanned outages that combine to a target annual unplanned outage rate. For the test year analysis, the RTSim model used the same unplanned outage rates as those used by Mr. Finnell in his PROSYM modeling to calculate the test year net fuel costs. The unplanned outage rates for 2009 through 2012 were based on AmerenUE's budget. The

NP

budgeted outage rates reflect improvements that the Company hopes to achieve through capital expenditures at the plants.

Q. How was the load uncertainty modeled?

A. The load uncertainty was modeled by using 250 different sets of hourly loads for each year of the study period. Each of the 250 sets of hourly loads was developed from a load model that accounts for weather uncertainty, growth, and calendar correctness. There are three steps to developing the 250 sets of hourly loads.

The first step is to develop monthly weather probability distributions. The primary weather variables are temperatures and humidity. The monthly weather probability distributions are used to develop 250 monthly weather patterns for each year.

The second step is to use the 250 monthly weather patterns as inputs to a regression model which converts the weather data to load data, thus creating 250 annual system loads. Also included in the step is the use of the actual loads to create realistic daily load shapes.

The third step is to align the load data into correct calendar sequence and to make the 250 annual load patterns converge to the targeted annual load. The calendar sequencing ensures that the data is calendar correct. For example, January 1, 2009 is a Thursday. For the purposes of this study, the target loads for 2008 were the same net output as the test year and the 2009 through 2012 loads were the same as the net output used in the current AmerenUE budget.

B. <u>The Relationship between AmerenUE Fuel Costs and Power Market Prices</u>

Q. You measure uncertainty around key variables that are inputs to the model. Given that the price of power relates to the costs of producing it from various fuels, did you consider how uncertainties in power and fuel prices relate to each other?

A. Yes, I did. I considered correlations between power and fuel prices, as well as the correlations between loads (temperature) and prices.

Q. How does the market price of power relate to fuel prices?

A. The market price for power is set by the marginal generation unit given system conditions with regards to load, generation availability and congestion. This means that the price will be related to the characteristics of that marginal generating unit, including its fuel type, heat rate, variable operating costs and other pertinent factors.

Q. Considering this relationship, would you expect off-system sales revenues to substantially offset coal cost increases because the market power price changes may be correlated with AmerenUE's coal cost changes?

A. No, I would not expect that changes in off-system sales revenues would substantially offset AmerenUE's coal cost changes because of several operational and market realities, which I address below. Indeed, I would not expect the market power price changes to be significantly correlated to AmerenUE's coal cost changes during either peak or off-peak periods.

Q. Please explain why you don't expect a significant correlation of changes in AmerenUE coal costs and on-peak power prices.

A. Even though the market price of power will be determined by the marginal offers (which may or may not reflect their true marginal cost) of generating units, the marginal offer of the "typical" generating unit that determines the power price may not be highly correlated with changes in AmerenUE coal costs for a number of reasons. First, during peak hours the power price may be set by the marginal offers of different "typical" generation units – coal or natural gas - with varying heat rates. Given this variance in the marginal generation unit, and the fact that AmerenUE coal costs are generally hedged in the near term, it is hard to see how a significant positive correlation between power prices and AmerenUE coal prices could exist for on-peak periods.

Q. Why do you not expect a significant correlation between AmerenUE coal costs and off-peak power prices?

A. Considering the off-peak period, AmerenUE coal costs are substantially hedged for the next few years, so no correlation would apply to the hedged portions of AmerenUE coal costs. With respect to the un-hedged portion of AmerenUE coal costs, correlations will again be limited because of AmerenUE generating units' heat rate and emission output profiles, maintenance schedules, coal transportation costs, and even coal commodity costs will differ significantly from the "typical" coal unit that will set off-peak power prices in the broader MISO footprint of which AmerenUE is a part. This is even more relevant when we consider that the marginal generation unit may vary every hour, day or month of the year because of market and system conditions and the factors affecting the marginal unit. For example, the marginal coal unit may be much less efficient than AmerenUE's units, as demonstrated by Schedule AKA-E4. Schedule AKA-E4 shows the stacking of AmerenUE's generating plants versus other plants within the MISO footprint. AmerenUE's plants are all toward the lower-cost end of this stack, meaning that AmerenUE plants are unlikely to be the marginal plants in the MISO. Other plants in the MISO that are more likely to be the marginal plants may burn a different type of coal (e.g., Illinois or Central Appalachian coal, not Powder River Basin coal), may be exposed to much higher incremental environmental allowance costs (e.g., for SO_2 or NOx), may be on a completely different outage schedule and may face very different coal transportation options.

Anticipated power market conditions may also change significantly over time (e.g., due to load growth, the addition or retirement of generation, new transmission lines, or new environmental investments), which may change power prices independently of any changes in coal prices whatsoever. Schedule AKA-E4 shows that AmerenUE's plants are "inframarginal" (i.e., below the marginal plant) to most other MISO coal plants. This means that off-peak power prices could shift significantly due to changes in market conditions without any underlying changes in coal prices. This also means that changes in AmerenUE's own coal costs will not result in corresponding changes in off-peak power prices.

Q. But wouldn't AmerenUE's coal costs be somewhat correlated to the coal costs faced by the units that set the off-peak power prices?

A. Perhaps somewhat, but not significantly. The fact that coal transportation costs account for the majority (approximately **[redacted]**) of AmerenUE's delivered coal cost means that even if the commodity portion of AmerenUE's coal cost were somewhat correlated with off-peak power prices, that would not translate into a significant correlation between off-peak power prices and AmerenUE's total delivered cost of un-hedged coal. This is because coal transportation costs are very much utility and even unit specific. Increases or decreases in AmerenUE coal transportation costs will not be correlated with power prices because other utilities will generally face very different coal transportation costs (e.g., the marginal coal-fired unit that sets off-peak power prices in the MISO may burn Central

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Appalachian coal and face much smaller coal transportation costs, as noted above). AmerenUE, with less than 9% of the total annual generation volume needed by the MISO market and generally lower costs than the market, will typically not be able to influence prices. As a result, I would not expect off-peak power prices to be significantly correlated to AmerenUE's fuel costs.

Q. Have you reviewed the historic relationship between AmerenUE coal costs, the incremental costs of dispatching coal power plants, and power prices?

A. Yes, I have. Average historic changes in AmerenUE coal costs, the spot prices for coal and emission allowances, and power prices are shown in Schedule AKA-E5. It shows that changes in AmerenUE coal costs have not been related to changes in power prices. The schedule also shows that for the years 2005 to 2007 (when the MISO market has been in operation) AmerenUE coal dispatch costs increased while wrap power prices (Saturday on-peak, Sunday on-peak and off-peak) declined, and conversely in 2007, the coal dispatch costs were steady while wrap power prices increased.

Q. Are there any operational reasons why you wouldn't expect a significant correlation between AmerenUE coal costs and its off-system sales revenues?

A. Yes. Another important reason why we would not expect any significant correlation between the hedged AmerenUE coal costs and AmerenUE off-system sales revenues has to do with the operational aspects of AmerenUE's fuel hedging strategy given power market realities. AmerenUE coal-fired units are generally lower in the generation dispatch stack for MISO, as shown on Schedule AKA-E4. As a consequence, changes in expectations of future forward or spot power prices do not necessarily change AmerenUE's modeled expectation of its coal fuel burn. Therefore, to dollar cost average the cost of its coal (see Mr. Neff's testimony), AmerenUE starts hedging its coal purchases several years in advance. However, while AmerenUE knows with some confidence its total coal burn, for several operational and market reasons it is not able to hedge its off-system sales at the same time it procures its coal.

Q. Please explain these operational and market reasons.

A. AmerenUE's inability to hedge its off-system sales at the same time it procures its coal is substantially driven by the fact that AmerenUE has an obligation to serve its native load, which means the MWhs it may have available to sell off-system are uncertain. In other words, its off-system sales profile has a certain shape – more off-peak, and shoulder month power sales, which is a shape inverse to the shape of its native load, and thus does not match well with the market power products available to hedge off-system sales, which are typically blocks of a fixed volume every hour. This mismatch, combined with the fact that the power markets are illiquid several years out (especially for the time period that AmerenUE has MWh that would be available for off-system sales – off peak and shoulder months) -- does not allow AmerenUE to hedge its power sales several years in advance, like it can do in part for coal. Another operational consideration is that the shape of AmerenUE's off-system sales, which as I noted is different than the shape of its native load, is itself uncertain because of the uncertainty of native load volumes, generation availability, and fuel and power prices. This too limits AmerenUE's ability to hedge its off-system sales.

Q. What off-system sales hedging can AmerenUE do?

A. AmerenUE can only hedge a portion of its MWhs which may be available for off-system sales up to approximately **[redacted]** into the future, and it can generally only hedge up to about **[redacted]** of those volumes for that year for the reasons noted

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earlier. By contrast, as discussed by Mr. Neff, AmerenUE can hedge a portion of its coal needs two, three, four and even five years into the future. The limits on AmerenUE's ability to hedge its off-system sales means that about **[redacted]** of its off-system sales must be made in the uncertain and volatile spot power market wherein, because of the reasons outlined above, there would be no expectation of any significant correlation between the fuel price changes that AmerenUE experiences and the actual realized spot power market prices for its off-system sales, even during the off-peak time period.

Q. So, what does this mean with regard to whether or not off-system sales may offset higher coal prices?

A. It means that it is highly unlikely that off-system sales revenues will offset higher coal prices for AmerenUE.

C. <u>Correlations Between Key Variables in the RTSim Simulations</u>

Q. Have you tested statistically the extent of to which high or low fuel prices may be offset by high or low power prices?

A. Yes. Whereas standard deviation describes the range of uncertainty in individual commodity prices, correlations describe how commodity price outcomes are interrelated. Therefore, one method of making the determination as to whether high or low outcomes in the prices of two commodities are likely to be coincident is to compute the correlation between them. For example, one could compute the correlation between the market prices of power with the market prices of coal or natural gas to see if high or low outcomes in these prices are likely to offset each other.

Q. How does one correctly calculate such correlations for the purpose of the type of simulations you have undertaken?

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A. An important thing to keep in mind when computing correlations between uncertain outcomes is that the relevant correlation applies to the uncertainty around the target forecast and not to variations in the target forecast itself. To estimate the correlation in the uncertainty of future price outcomes, we typically examine whether historical *changes* in forward prices for one commodity are reflected in simultaneous *changes* in the forward prices for another commodity. The forward price of a commodity is a type of price forecast and changes in forward prices reflect changes in forecasts as information is learned about uncertain future outcomes. If, for example, power price uncertainty and coal price uncertainty were highly correlated then we would expect information that moves power forward prices would correspondingly move coal forward prices, and vice-versa. Hence we compute our correlations using simultaneous movements in prices (i.e. price changes) to see which uncertainties are likely to have coincident high or low outcomes. When the resultant price changes are correlated it can become clearer as to whether or not the commodity prices effectively move together. This is the most important consideration in determining if the uncertainty of fuel prices may potentially be offset by the uncertainty of power prices.

Q. What would happen if you computed correlations using forward price levels instead of forward price differences?

A. Computing correlations with forward price *levels* instead of forward price *differences* will distort the results (by mingling the effects of prior price moves with current price moves) and can produce numerically very different results as can be seen in the following example. If we correlate the 2009 forward price for 8800 Btu/lb. PRB coal and the 2009 forward off-peak power price from January 2006 through December 2007, the resultant correlation is 61.1%, which would indicate a relationship between coal prices and off-peak power prices. However, the 2009 forward price *change* for 8800 Btu/lb. PRB coal and the 2009 forward price *change* for off-peak power prices for the same period had correlation of only 1.5%, which shows no relationship between the two items. The low correlation between these price changes demonstrates that it would be inappropriate to conclude that increases in coal prices will be off set by increases in the power prices received for off-system sales.

This same phenomenon can be seen visually in Schedule AKA-E6-1 where AmerenUE has compared the coal prices to power prices in one chart and then compared the coal price changes and power price changes in the following two charts (one on Schedule AKA-E6-1 and the other on Schedule AKA-E6-2). The first chart seems to indicate that the coal price and power prices may be correlated – even though there are several time periods where they diverge. However, the next two charts that compare price changes between coal and power clearly demonstrate that the two commodity prices (coal and power) are not correlated.

The lack of correlation is shown first on the second chart because the price changes for coal (shown in blue) very often move in the opposite direction as the price changes for off peak power (shown in pink). It is also shown on the scatter plot in the third chart since the data points (the dots, which represent each coal price change and power price change) are scattered around zero.

Q. Please describe how you measured and modeled specific correlations between the key variables used as inputs to RTSim?

A. We tested several correlations between key variables that are appropriate for the model's operations. The correlation tests included: annual forward coal price changes and forward power market price changes for various pricing periods; daily natural gas price changes and power price changes; loads and power prices; and loads and natural gas prices. Since we were most interested in determining whether any offsets to net fuel costs existed from the prices of the key commodity variables, the correlation was included in the simulation model only when the correlation tests for the commodities demonstrated a statistically significant correlation. In most cases, correlations were computed based on two years of daily data. Using this number of data samples, an estimated correlation would only differ from zero by a statistically significant amount at the 95% confidence level if the correlation estimate had a magnitude of about 9% or greater.

Q. What is the correlation between coal price change and power price change?

A. A correlation test was done using long-term forward coal and power price changes for various pricing periods. The use of long-term coal price changes is appropriate since AmerenUE uses long-term coal purchases rather than spot for which these long-term prices were evaluated included the off-peak, the wrap pricing periods and the ATC pricing period.

The first correlation analysis was done using coal price change and off-peak power price change. This is where I would expect to see the most correlation since it would effectively be looking at a time period (off-peak) where the power price changes should be determined by the operation and market impact of a marginal coal unit, as I addressed earlier. In order to further test for the presence of a correlation between the price changes in this time period, I removed any variation that would be present from transportation costs and rail surcharges, etc. I then compared just the commodity portion of the fuel price, for which the correlation should be highest. The correlation should be highest between the commodity portion of the fuel price and power prices because of the influence of unit-specific factors that cannot be expected to affect the overall market has been removed. The coal price change was calculated using 8800 PRB coal price quotes from the period January 2006 through December 2007 for annual contracts with delivery in 2009. The off-peak power price change was calculated using forward off-peak power price quotes from the period January 2006 through December 2007 for forward contracts with delivery in 2009. The correlation between the forward PRB coal price change and the forward off-peak power price change was only 1.5%, far below the 9% or greater correlation necessary to find a statistically significant correlation, as noted above.

Since this correlation was low, I further tried to remove any bias that may have been introduced because of the granularity of the daily data and tested the correlation of price changes based on monthly averages. The correlation between the price change of monthly average changes in forward prices of annual PRB coal and off-peak price change was 22.7% -- a number that is also not statistically significant given the small number of monthly observations available for the calculation (24 monthly average prices leading to 23 monthly price changes). Thus, a correlation between coal price changes and off-peak power price changes was not included in the simulations.

A second correlation analysis was done using coal price change and wrap power price change. Using data from the same time period as for the off-peak analysis, the correlation was calculated to be less than 1%, which is statistically insignificant. Thus, a correlation for coal price change and wrap power price change was not included in the simulations.

A third correlation analysis was done using coal price change and ATC power price change. Using data from the same time period as the off-peak analysis, the correlation was calculated to be nearly 3%, which is also statistically insignificant, and thus a correlation between these changes was also not included in the simulations.

A graphical representation of the correlation results between coal prices and the three types of power prices is shown in Schedule AKA-E6-2. Because the forward looking correlation between the (un-hedged) annual market prices for coal and power is minimal, and the correlation between (substantially hedged) AmerenUE future delivered coal contract prices and power prices will be even smaller, as noted, no correlation was included in the simulation model for AmerenUE coal price and power prices.

Q. What is the correlation between natural gas price changes and power price changes?

A. We analyzed the correlation of daily, monthly and average annual natural gas price and power price changes. We found that monthly correlations between natural gas price changes and power price changes are in the range of 27% to 47%. See Schedule AKA-E7. However, as discussed earlier, because of the substantial uncertainty of AmerenUE's gas generation forecast, a majority of the natural gas used for generation is purchased on a daily basis in the spot market. Thus, we also needed to test the correlation between daily natural gas price change and daily peak power price change. The correlation test was run using data from the daily natural gas prices for Chicago City Gate and Cinergy Day Ahead on-peak power prices for the period January 2006 through December 2007. The natural gas prices for Chicago City Gate were used because they are representative of the natural gas prices for generators in the MISO energy market. The correlation between daily natural gas price change and daily peak power price change was 12% and is shown in Schedule AKA-E8. Because AmerenUE does not hedge its natural gas purchases and power sales for its natural gas generating units, due to highly uncertain natural gas generation levels and the day-to-day operation of these generating units, this short-term correlation is the relevant correlation for modeling purposes.

Although this estimated correlation is statistically significant, it is only marginally so (just three percent above the 9% threshold noted earlier) and is still quite low. Because of this small correlation, the fact that the modeled annual uncertainty factor for natural gas is only about one-third of the historical annual uncertainty factor (as discussed above), and given the current relatively small amount of natural gas generation as compared to total AmerenUE generation, I decided to simplify the modeling effort by not including a natural gas-power price correlation. The impact of this simplification on the overall uncertainty analysis results is offset by the conservative level of the simulated annual uncertainty factor for natural gas and the small amount of natural gas generation.

Q. What is the correlation between loads and power price?

A. The level of the AmerenUE loads has a significant impact on how much excess energy is available for off-system sales, and the power price at the time of the sales will directly impact the revenues collected from off-system sales. Therefore we included the correlation between loads and power prices. AmerenUE loads are a function of many variables, such as temperature, humidity, day of the week, etc., so loads were not directly used in the correlation test. Since the AmerenUE load is very temperature sensitive, we replaced loads with temperature in the correlation analysis. The temperature data were St. Louis hourly temperatures from January 2006 through December 2007. The temperature data were organized by month and by day type. The day types used were weekday (Monday through Friday), Saturdays, and Sundays. The correlations between temperatures and power prices ranged from -90% to +80% and are shown in Schedule AKA-E9. The strong negative correlation occurs in the winter periods when temperatures fall and loads and power prices increase. The positive correlation occurs in the summer months when temperatures rise and loads and power prices increase. These correlations between temperatures (loads) and power prices were included in the modeling.

Q. What is the correlation between loads and natural gas prices?

A. AmerenUE's CTG fleet, whose primary fuel is natural gas, is typically used to meet summer peak demand. For example, during 2007, 49% of the natural gas generation occurred during the summer months of June, July and August. Thus, a correlation analysis for loads and natural gas prices was deemed appropriate. As described in the explanation of correlation analysis for load and power price, a correlation test was done using temperature as a substitute for load. The same time periods were also used for the load and natural gas price analysis. As with the other analysis using natural gas price data, the daily spot market price was also used. The correlation between temperature (load) and natural gas prices ranged from -62% to +41%, as shown in Schedule AKA-E10. As with the power price correlation, the strong negative correlation occurs in the winter months when temperatures are low and natural gas use increased due to heating loads. The positive correlation occurs in the summer period when natural gas is used to meet peak electric needs. These correlations between temperatures/loads and natural gas prices were included in the modeling.

D. Simulation Results for Net Fuel Cost Uncertainty

Q. Putting all of these variables (power prices, coal prices, natural gas prices, nuclear prices, loads, and outages) together, what are the uncertainty analysis results produced from the RTSim modeling?

A. The RTSim model calculated and reported the annual net fuel costs for each of the 250 iterations. Each iteration is a production cost model run based on the data that were selected for use in that iteration. For example, Iteration #1 uses the power price assumption assigned to Iteration #1, loads assigned to Iteration #1, pattern of unplanned outages assigned to Iteration #1, and where appropriate the coal, natural gas, and nuclear fuel costs assigned to Iteration #1. This process was repeated 250 times, one time for each iteration, and produces 250 calculations of annual net fuel costs that reflect the uncertainties, correlations, and hedge ratios used as input parameters, which I described earlier. Schedule AKA-E11 is a graphical representation of all 250 iterations of the annual net system fuel costs for test year case and for the years 2009-2012.

I have also prepared Table 1, which is shown below, to highlight the results of the RTSim model. Note, however, that the RTSim net fuel costs reported in Table 1 are similar to the net fuel costs calculated by Mr. Finnell using his PROSYM model. Those net fuel costs include only fuel costs, the variable component of purchased power and off-system sales revenues.[4]

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[4] The following costs need to be added to the net fuel costs in order to calculate the “net base fuel costs” used in the FAC, as discussed in Mr. Lyons’s testimony: fixed natural gas supply costs, credits from Westinghouse for a prior settlement involving a nuclear fuel contract, MISO Day 2 costs, excluding administrative fees, MISO Day 2 congestion and revenue expenses, MISO Day 2 Revenues, and capacity sales.

TABLE 1

Net Fuel Cost Uncertainty (millions of $)

Percentile	Test Year with Uncertainty	2009	2010	2011	2012
10%	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
25%	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
Average	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
75%	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
90%	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
25%-75% Range	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
10%-90% Range	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**

The row labeled "average" is the average RTSim net fuel costs of all 250 iterations for each year. The other rows list the percentile or the probability that the net fuel costs will be *less than or equal to* the net fuel costs shown in that row. For example, while from the perspective of the beginning of the test year the average net fuel costs were calculated to be $**[redacted]** million, there was a 25% chance that the net fuel costs would have been less than $**[redacted]** million and another 25% change that net fuel costs would have been greater than $**[redacted]** million. This means there is a 50% change that net fuel costs would be outside this range. This large $**[redacted]** million uncertainty range between even the 25th percentile and the 75th percentile for the test year case—from $**[redacted]** million below average to $**[redacted]** million above average net fuel costs—demonstrates the significant uncertainty in net fuel costs. This uncertainty is even more significant because the test year case takes into account the fact that AmerenUE had already hedged a significant portion of its uncertainty for the test year, and will have done so going into particular future 12 month periods. As shown in Table 1, despite the substantial risk mitigation this hedging provided

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for the test year, there was still a 20% chance that the uncertainty range in net fuel costs (i.e., the range between the 10th percentile and the 90th percentile) could have exceeded $**[redacted]** million. Stated another way, going into the test year, even with substantial hedges in place, there was still a 20% chance that AmerenUE's net fuel costs could have varied by more than $**[redacted]** million.

The Table 1 results not only demonstrate the uncertainty faced immediately before a specific year, it also illustrates how the uncertainty in net fuel costs increases over time. For example, as of February 2008, the 2012 swing between the 25th percentile and "average" and "average" to the 75th percentile exceeds $**[redacted]** million, from **[redacted]** million to **[redacted]** million.

Q. Can you identify the reasons for the swings in the net fuel costs?

A. The swings in net fuel costs can be analyzed by looking at the individual RTSim iterations that have results similar to the uncertainty ranges discussed above. While looking at individual simulations does not provide a comprehensive picture of how individual components combine to create the uncertainty of net fuel costs, this nevertheless provides a realistic illustration for how these cost components interact to create the measured uncertainty. For example, Iteration No. 115 of the test year simulations had a net system fuel cost of $**[redacted]** million and is the representative case for "average" net fuel costs. Similarly, Iteration No. 77 had net fuel costs of $**[redacted]** million and is the representative case for the 25th percentile and Iteration 140 had a net fuel cost of $**[redacted]** million and is the representative case for the 75th percentile.

Table 2 below lists the components of net fuel costs: total fuel costs, purchased power costs and off-system sales for the various percentiles for the test year.

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Table 2 Average Net Fuel Costs – Test Year Net Fuel Cost Components ($ Million)					
Percentile	Iteration #	Fuel Costs	Purchased Power Costs	Off- System Sales Revenues	Net Fuel Cost
25%	77	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
Average	115	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
75%	140	$**[redacted]**	$**[redacted]**	$**[redacted]**	$**[redacted]**
25%-75% Range		$**[redacted]**	$**[redacted]**	$**[redacted]**	**[redacted]**

The data from Table 2 indicates that the off-system sales uncertainty has the biggest impact on net fuel costs from the perspective at the beginning of the test year.

Q. What does this data indicate respecting whether off-system sales revenues offset the increase in fuel costs going forward over time?

A. Table 3 below lists the components of net fuel costs: total fuel costs, purchase power costs and off-system sales revenues for the test year and 2009 through 2012.

	Table 3 Average Net Fuel Cost Components – Test Year, 2009-2012			
	($ Million)			
Average	Fuel Costs	Purchased Power Costs	Off- System Sales Revenues	Net Fuel Cost
Test Year	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
2009	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
2010	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
2011	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**
2012	**[redacted]**	**[redacted]**	**[redacted]**	**[redacted]**

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As I addressed earlier, the data indicates that while off-system sales revenues can offset fuel costs under certain conditions, most of the time, this is not the case. An offset did occur between the test year and 2009; however, from 2009 to 2010 average fuel costs increase while off-system sales revenues decline resulting in no offset. For the entire study period, test year to 2012, the fuel cost increased by $**[redacted]** million and revenues from off-system sales increased $**[redacted]** million, with an overall increase in net fuel costs of $**[redacted]** million. Thus, the data confirms the opinion I expressed earlier that off-system sales revenues cannot generally be expected to offset fuel cost increases.

Q. Do you think that the modeling of uncertainty in net fuel costs through the process outlined above results in realistic depiction of the uncertainty?

A. Yes, it does. In fact, AmerenUE has been conservative in its modeling of the uncertainty for a number of reasons. First, we have modeled "hedged" fuel and transportation costs as fixed-priced costs when, in fact, these prices may not be fixed (e.g., they may only be capped or they may be indexed to increase over time). Second, the modeling may be conservative in the modeling of uncertainty of coal prices – as outlined earlier the annual uncertainty factor of the PRB coal was **[redacted]** as compared to a historical annual uncertainty factor of 31%. Similarly, the natural gas price annual uncertainty factor was **[redacted]** versus a historical uncertainty factor of 36%. Because of these factors, I believe that the uncertainty of the net fuel costs is realistic and may be somewhat conservative.

Q. Please summarize your conclusions.

A. There is a large amount of uncertainty around net fuel costs and this uncertainty can be either a reduction in net fuel costs from an expected or average level of

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net fuel costs or there can be an increase in net fuel costs, as was illustrated in Table 1. In the short-term, the uncertainty is due to load uncertainty, generating availability uncertainty, natural gas price uncertainty, and power price uncertainty. However, the uncertainty in net fuel costs increases over time due to the factors affecting short-term uncertainty, as well as the uncertainty surrounding the un-hedged portions of coal and nuclear fuel prices. Even though more of these fuel costs will be hedged at the beginning of each year than the proportion that is hedged right now, the uncertainties when looking forward from today (i.e., the time of the rate case) are larger than at the beginning of a particular year because we do not know today at what cost AmerenUE will be able to hedge fuel between now and the beginning of any particular future year.

The simulation analysis also confirmed the qualitative discussion earlier in my testimony that changes in off-system sales revenues cannot generally be expected to offset changes in AmerenUE's fuel costs.

Q. Does this conclude you 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-2008-____

AFFIDAVIT OF AJAY K. ARORA

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

Ajay K. Arora, being first duly sworn on his oath, states:

1. My name is Ajay K. Arora. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Director of Corporate Planning.

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 33 pages, Attachment A and Schedules AKA-E1 through AKA-E11, 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.

Ajay K. Arora

Subscribed and sworn to before me this 4th day of April, 2008.

Danielle R. Moskop
Notary Public

My commission expires:

Danielle R. Moskop
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: July 21, 2009
Commission # 05745027

EXECUTIVE SUMMARY

AJAY K. ARORA

Director of Corporate Planning

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The purpose of my testimony is to document the uncertainty of AmerenUE's net fuel costs which, in turn, provides support for one of the bases addressed by AmerenUE witness Martin J. Lyons, Jr. in his direct testimony relating to AmerenUE's request to implement a fuel adjustment clause ("FAC"). Net fuel costs are the Company's fuel, fuel transportation, and purchased power costs, net of off-system sales revenues.

I have first quantified the uncertainty in net fuel costs that the Company faced at the beginning of the test year, considering AmerenUE's typical "hedge ratios" at the beginning of a year. This documents that significant net fuel cost uncertainty remains even at the beginning of each year, despite the risk mitigation that is achieved by the Company's substantial hedging and long-term contracting efforts. I then also quantified the net fuel cost uncertainty that can be expected during the years 2009 through 2012, considering AmerenUE's hedged (or known) positions with respect to fuel, purchased power, and off-system sales as of February 2008. Even though more of AmerenUE's costs will be hedged at the beginning of each of these years, the uncertainties when looking forward from the time of the rate case are larger than those at the beginning of a particular year because we do not know at what cost we will be able to hedge fuel between now and the beginning of any particular future year.

I do not expect changes in AmerenUE off-system sales revenues to substantially offset AmerenUE's coal cost changes because of several operational and market realities. First, AmerenUE's coal-fired generating units are generally lower cost than many of the other coal-fired units within the footprint of the Midwest Independent Transmission System Operator, Inc. ("MISO"), as shown on Schedule AKA-E4. The market price of power in the MISO is set by the marginal (highest cost) generating unit, which means that power prices are related to the characteristics of that marginal unit, including its fuel type, heat rate, variable operating costs and other pertinent factors. For example, AmerenUE's coal-fired plants burn Power River Basin, Wyoming coal, and transportation costs are approximately **[redacted]** of AmerenUE's delivered coal costs. Even when coal plants determine the market price of power (e.g., mostly during off-peak periods) other coal plants in the MISO footprint that are more likely to be the marginal unit may burn a different type of coal (e.g., Illinois or Central Appalachian coal), may be exposed to higher incremental environmental allowance costs (e.g., for SO_2 or NO_x), and may face very different coal transportation options. Anticipated power market conditions may also change significantly over time (e.g., due to load growth, the addition or retirement of generation, new transmission lines, or new environmental investments), which may change power prices independently of any changes in coal prices whatsoever. Consequently, changes in AmerenUE's own coal costs cannot be expected to be offset significantly by corresponding changes in power prices.

Second, while AmerenUE can hedge its delivered coal costs from one to five years into the future (with a lower percentage of the costs hedged further into the future), the Company is not able to hedge its off-system sales at the same time it procures its coal. This is because the shape of AmerenUE's native load profile, which AmerenUE has an obligation to serve, results in AmerenUE's off-system sales profile being mismatched with standard market products available to hedge off-system sales. This mismatch, coupled with the illiquidity in the off-system sales markets several years out, does not allow AmerenUE to hedge its off-system sales the way it can

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hedge its exposure to coal markets. This means it is highly unlikely that changes in off-system sales revenues will offset any changes in AmerenUE's fuel costs.

I have conducted a detailed simulation analysis that confirms the foregoing discussion, and that also shows a high level of uncertainty and volatility in AmerenUE's net fuel costs. Specifically, I have used a probabilistic production cost model, RTSim, to estimate uncertainties in net fuel costs, which represent the *combined* uncertainty forecasts for power prices, native load and off-system sales quantities, plant outages, and the market prices for coal, natural gas, and nuclear fuel, considering AmerenUE's long-term contracting and hedging practices. The RTSim model also incorporates relevant operational data such as the use of spot natural gas prices rather than long-term natural gas prices and correlations between variables, such as temperatures and power prices.

For each uncertain variable, a statistical measure of the average annual dispersion around the base forecast for that variable was computed (which I refer to as the "annual uncertainty factor"). These uncertainties were then applied to "targets" (that is, the average anticipated values) for each of the uncertain variables. In addition, correlation measures of how the uncertainty in one variable is related to the uncertainty in other variables were estimated. The combination of these "targets" and uncertainty parameters, including correlations between key variables, is what results in an average level of annual net fuel costs and an uncertainty range around that average value.

Using these parameters, 250 scenarios of joint outcomes for the uncertain variables were developed that reflected the dispersion and the estimated correlations between the variables. RTSim was then run for each year to compute AmerenUE's net fuel cost for each of the 250 input scenarios. The dispersion of the 250 RTSim computations of AmerenUE's net fuel cost demonstrates the uncertainty in AmerenUE's annual net fuel costs.

The results of this simulation analysis demonstrate that there exists substantial uncertainty and volatility in AmerenUE’s net fuel costs. For example, the modeling indicates that even under the substantially hedged positions the Company typically has at the beginning of a particular year, there is (1) a 50% chance that the uncertainty range in net fuel costs (i.e., the range between the 25th percentile and the 75th percentile of the distribution of possible net fuel costs) is more than $**[redacted]** million a year; and (2) a 20% chance that the uncertainty range in net fuel costs exceeds $**[redacted]** million a year (i.e., representing the difference between the 10th and 90th percentile of the distribution of possible net fuel costs).

Although these potential swings in annual net fuel costs are quite large, even when substantial fuel cost hedges are in place at the beginning of a year, the uncertainty range of annual net fuel costs is even larger for future years that are not as extensively hedged at this point. For example, in 2009 there is a 50% chance that the Company’s net fuel costs will be less than $**[redacted]** million or more than $**[redacted]** million. In other words, there is a 50% chance that the uncertainty range *exceeds* $**[redacted]** million. In fact, there is a 20% chance that the uncertainty range (i.e., the range between the 10th and 90th percentile) exceeds $**[redacted]** million in 2009.

Finally, the simulation analysis confirms my opinion about the lack of an off-system sales revenue offset against AmerenUE’s fuel cost increases. For example, for the entire study period, test year to 2012, the target net fuel costs increased by $**[redacted]** million while target revenues from off-system sales increased just $**[redacted]** million, resulting in an overall increase in net fuel costs of $**[redacted]** million.

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Schedule AKA-E1

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Annual Uncertainty Factors - Historic

Annual Average ATC Power Price

Yr		$/MWh
1999	$	31.34
2000	$	28.74
2001	$	28.73
2002	$	23.19
2003	$	30.31
2004	$	34.25
2005	$	46.74
2006	$	39.01
2007	$	41.94
Average	**$**	**33.80**
Standard Dev.	**$**	**7.44**
Uncertainty Factor		**22%**

Annual Average Natural Gas Price

Yr		$/MMBtu
1999	$	2.31
2000	$	4.44
2001	$	4.04
2002	$	3.33
2003	$	5.55
2004	$	5.85
2005	$	8.43
2006	$	6.55
2007	$	6.83
Average	**$**	**5.26**
Standard Dev.	**$**	**1.91**
Uncertainty Factor		**36%**

Annual Average Coal Price

Yr		$/MMBtu
1999	$	4.50
2000	$	5.00
2001	$	9.00
2002	$	6.50
2003	$	7.00
2004	$	7.00
2005	$	12.00
2006	$	9.00
2007	$	10.00
Average	**$**	**7.78**
Standard Dev.	**$**	**2.43**
Uncertainty Factor		**31%**

Annual Average Heating Oil Price

Yr		$/Gal
1999	$	0.49
2000	$	0.84
2001	$	0.71
2002	$	0.69
2003	$	0.84
2004	$	1.13
2005	$	1.64
2006	$	1.84
2007	$	2.04
Average	**$**	**1.14**
Standard Dev.	**$**	**0.56**
Uncertainty Factor		**50%**

Notes:
Uncertainty Factor = Standard Deviation / Average
Coal price for 8,800 Btu/lb and 0.8 # SO_2/MMBtu coal

Schedule AKA-E3

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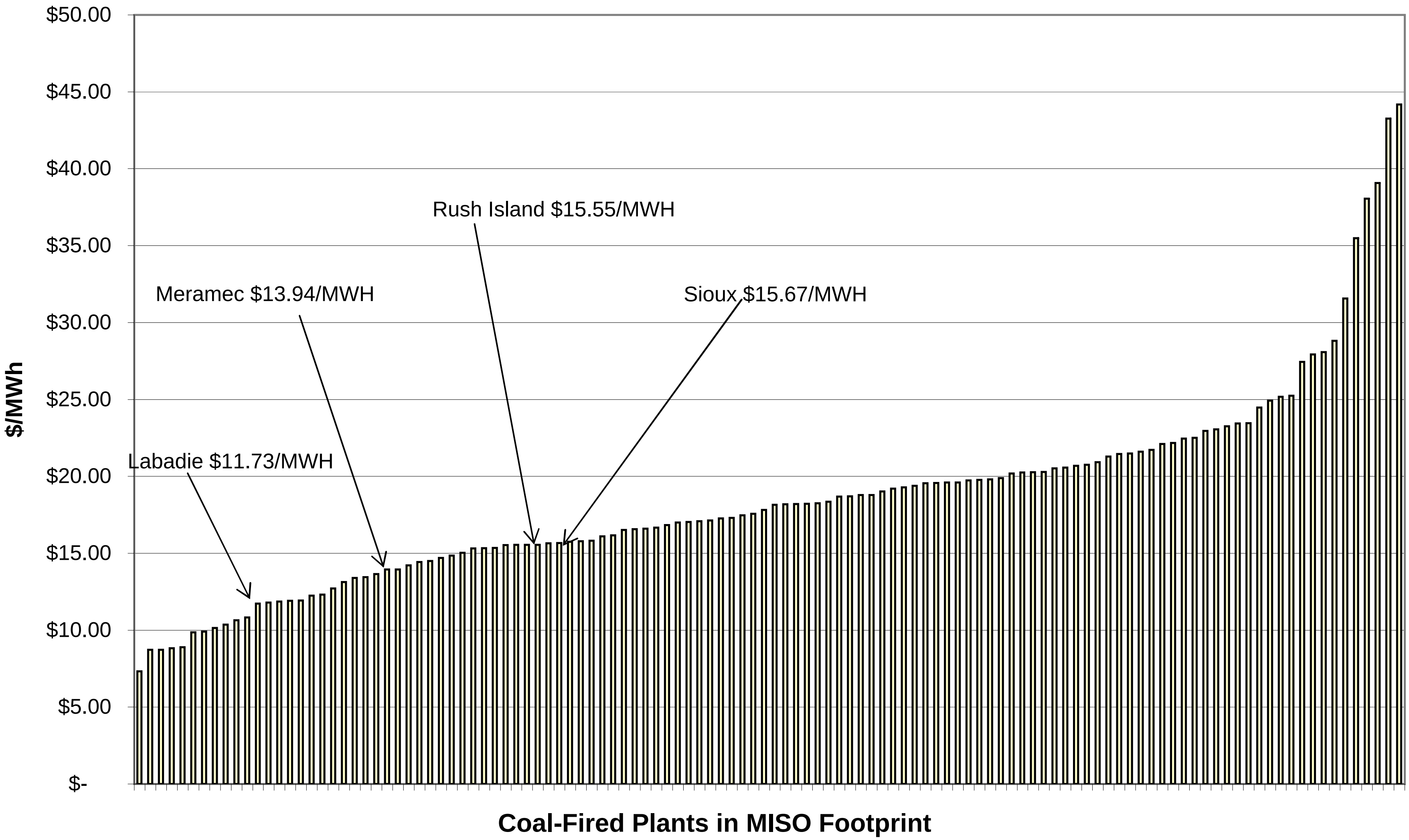
MISO Plant Coal Cost 2007



Schedule AKA-E4

Schedule AKA-E5

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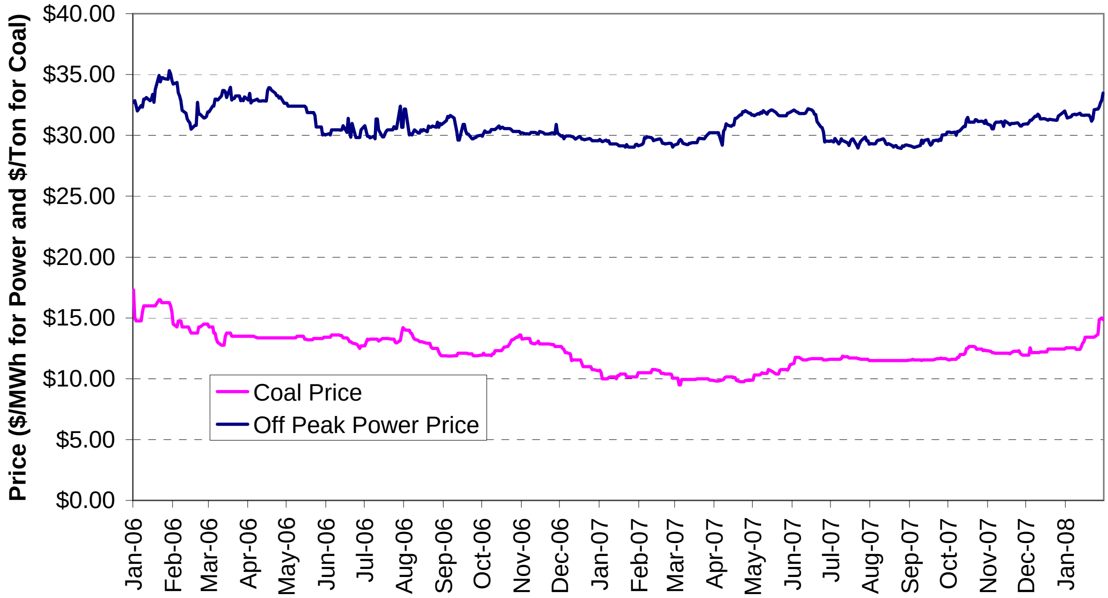
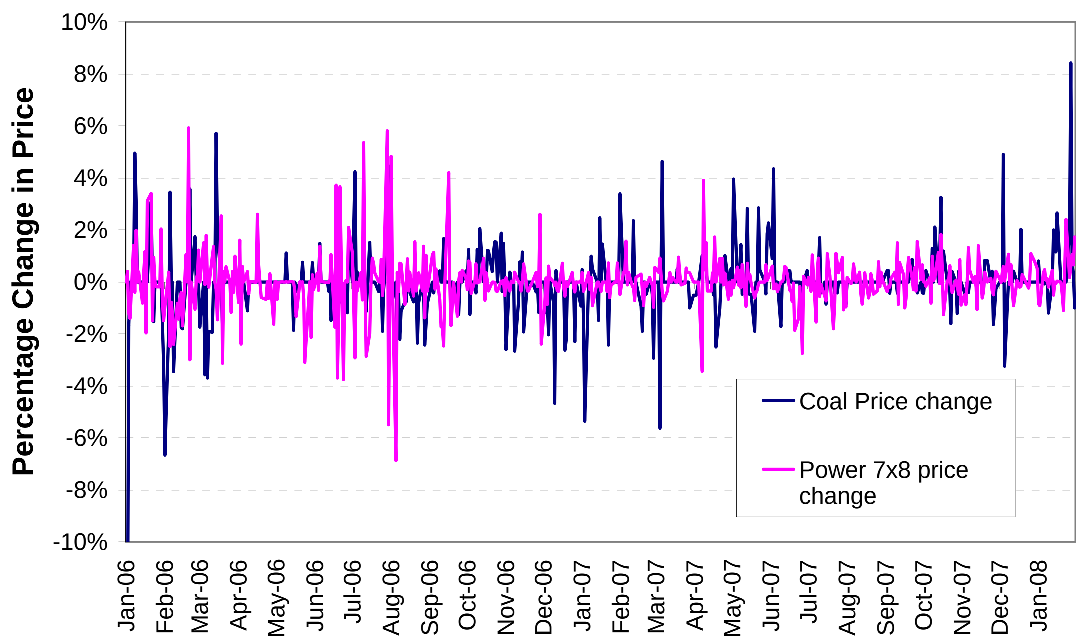
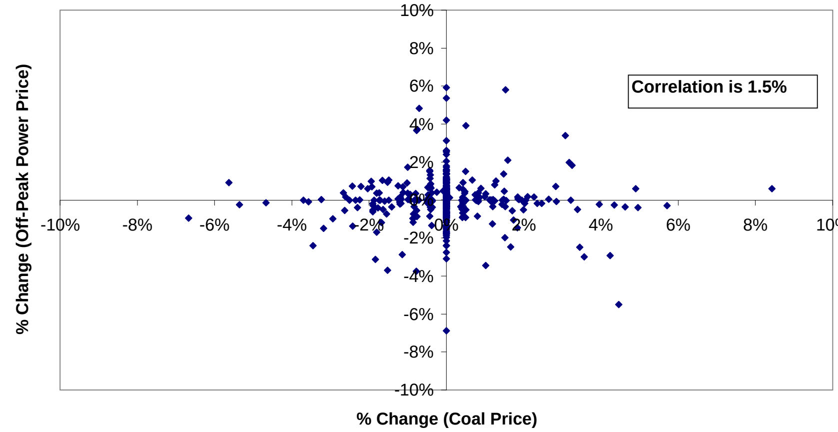
Annual Off-Peak (7x8) Power Prices and Annual Coal 8800 Prices



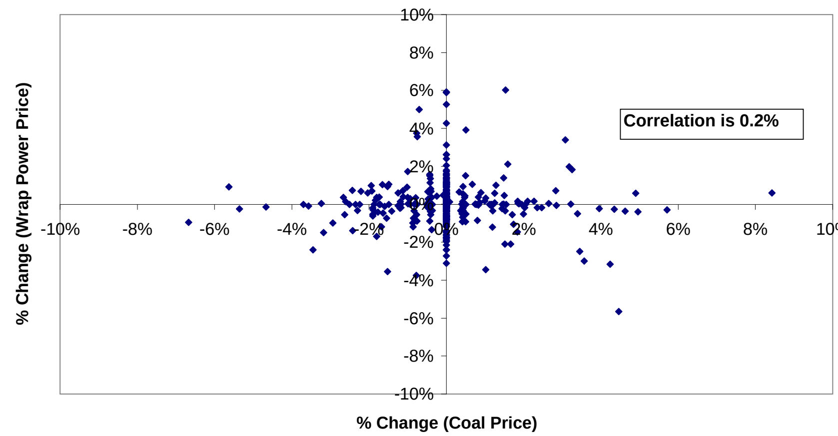
Annual Off-Peak (7x8) Power Price Changes and Annual Coal 8800 Price Changes



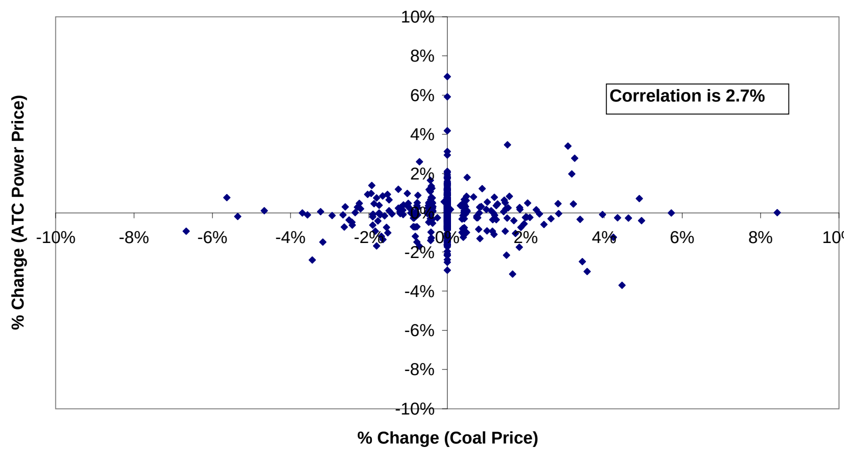
Annual Off-Peak (7x8) Power Price Changes vs. Annual Coal 8800 Price Changes



Annual Wrap Power Price Changes vs. Annual Coal 8800 Price Changes



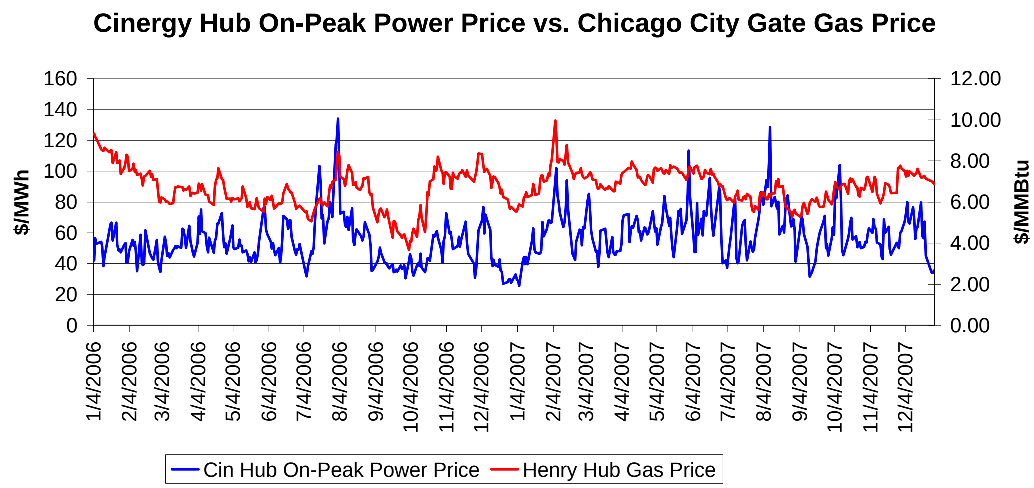
Annual ATC Power Price Changes vs. Annual Coal 8800 Price Changes

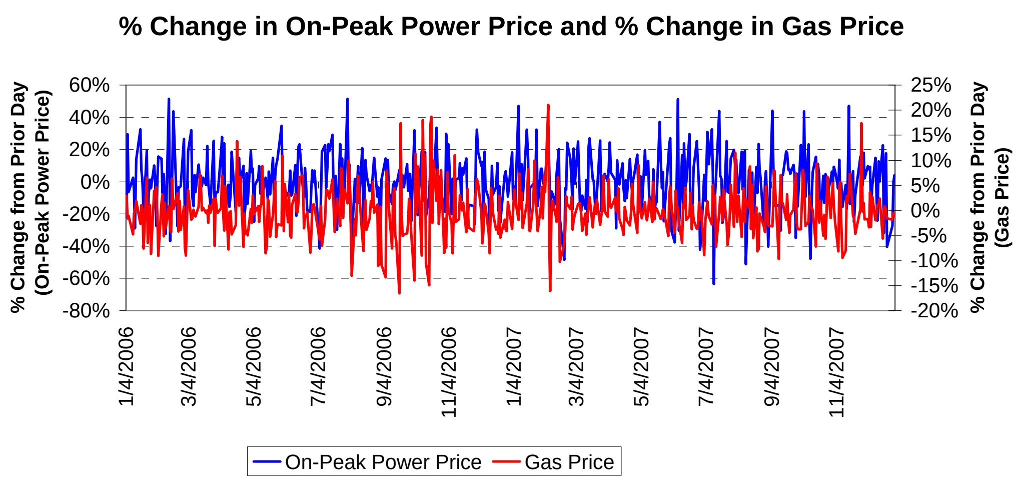


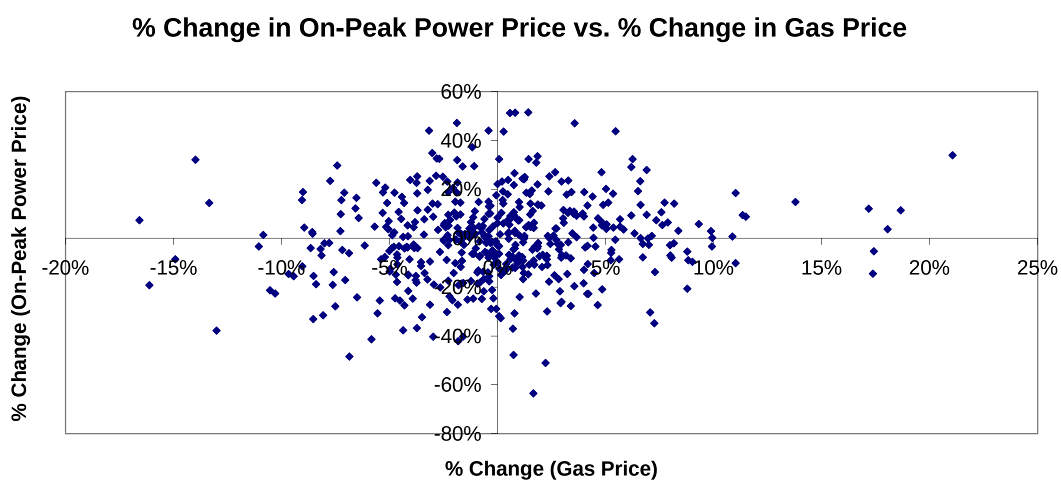
	Correlation of Monthly Forward On-Peak Power Price Changes and Monthly Forward Gas Price Changes
Jan	36%
Feb	39%
Mar	47%
Apr	44%
May	37%
Jun	33%
Jul	38%
Aug	38%
Sep	32%
Oct	28%
Nov	28%
Dec	27%

Notes:
Forward prices quoted in 2006-2007 for delivery in 2008-2009.

Correlation of Changes in On-Peak Power Price and Changes in Gas Price = 12%







Correlation of Power Prices and Temperatures

Month	Weekday On-Peak Power Prices vs. Temperatures	Saturday 16-Hour Power Prices vs. Temperatures	Sunday 16-Hour Power Prices vs. Temperatures	Off-Peak (7x8) Power Prices vs. Temperatures
1	-39%	-10%	-16%	-33%
2	-75%	-51%	-46%	-62%
3	-51%	-85%	-90%	-60%
4	-23%	-65%	-47%	-76%
5	36%	56%	66%	-5%
6	34%	30%	73%	31%
7	71%	65%	76%	64%
8	60%	37%	74%	47%
9	62%	58%	36%	-15%
10	47%	80%	63%	20%
11	-38%	-7%	-49%	-39%
12	-71%	-55%	-45%	-60%

Correlation of Natural Gas Prices and Temperatures

Month	Weekday On-Peak Gas Prices vs. Temperatures	Saturday 16-Hour Gas Prices vs. Temperatures	Sunday 16-Hour Gas Prices vs. Temperatures
1	-26%	-26%	-26%
2	-30%	-30%	-30%
3	-2%	-2%	-2%
4	-34%	-34%	-34%
5	5%	5%	5%
6	11%	11%	11%
7	23%	23%	23%
8	7%	7%	7%
9	41%	41%	41%
10	-20%	-20%	-20%
11	-2%	-2%	-2%
12	-62%	-62%	-62%

Schedule AKA-E11

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HIGHLY CONFIDENTIAL