MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT

COST OF SERVICE

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

FILE NO. ER-2011-0028

Jefferson City, Missouri
February 8, 2011

REVENUE REQUIREMENT COST OF SERVICE REPORT

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I. Executive Summary

The Staff has conducted a review in File No. ER-2011-0028 of all revenue requirement cost of service components (capital structure and return on rate base, rate base, depreciation expense and other operating expenses) which comprise Union Electric Company's d/b/a Ameren Missouri (Ameren Missouri or Company) Missouri jurisdictional revenue requirement. This audit was in response to Ameren Missouri's filing made on September 3, 2010, seeking to increase its Missouri jurisdictional retail rates to recover an additional approximately $263 million on an annual basis.

The Staff's recommended increase in revenue requirement is based upon an adjusted test year for the twelve months ending March 31, 2010, including true-up estimates through February 28, 2011. The Staff's recommended revenue requirement for Ameren Missouri is $44,789,202 to $99,306,105 based on a return on equity (ROE) range of 8.25% to 9.25%.

The impact of the Staff's recommended revenue requirement for each retail rate customer class will be addressed in the Staff's rate design direct testimony and report that is to be filed on February 10, 2011.

Staff Expert/Witness: Stephen M. Rackers

II. Background of Ameren Missouri

Ameren Missouri provides electric utility service to approximately 1.2 million retail customers primarily in the eastern half of Missouri, but also to a limited extent in northwestern Missouri. Ameren Missouri is wholly owned by Ameren Corporation, which also provides utility service in Illinois through its Ameren Illinois operating subsidiary. Ameren Missouri also operates a natural gas distribution business in Missouri, which serves approximately 126,000 customers.

Ameren Missouri last sought a general change of its Missouri jurisdictional electric retail rates when it filed for a $402 million annual increase on July 24, 2009, in File No. ER-2010-0036. As a result of the Commission's Report and Order in that proceeding, Ameren Missouri was granted a general annual rate increase of approximately $229.6 million, effective June 21, 2010.

Staff Expert/Witness: Stephen M. Rackers

III. Test Year/True-Up Period

Ameren Missouri filed its case based upon a twelve month ending March 31, 2010 test year and made adjustments to its case to reflect the impacts of anticipated changes through February 28, 2011, its requested true-up period end date. These dates were ordered by the Commission on November 10, 2010, in its Order Adopting Procedural Schedule And Establishing Test Year.

The Staff's revenue requirement as presented in its Accounting Schedules includes expected changes for a true-up ending February 28, 2011 based on current information. For example, the plant and depreciation reserve balances have been adjusted to reflect the anticipated additions through the February 28, 2011 true-up period. Fuel expense has also been adjusted, based on the January 2011 coal contract prices. The Staff expects to consider changes to these items, as well as additional components of the cost of service during the true-up audit. The Staff is not adopting now for the purpose of setting Ameren Missouri's rates the items listed and quantified in the Staff's true-up estimate. The Staff has included these items as placeholders, pending the Staff's completion of its true-up audit.

Staff Expert/Witness: Stephen M. Rackers

IV. Major Issues

The following are the major issues between the Staff and Ameren Missouri based on their respective prefiled direct revenue requirement cases. These issues are discussed here because of their estimated revenue requirement dollar value. A brief explanation for each issue follows, together with an estimate of the dollar value of the difference between the positions of the Staff and Ameren Missouri on the issue.

Return on Equity (ROE) – Issue Value – ($125 million difference based on applying difference in ROEs to the rate base presented by Ameren Missouri). The Staff is recommending a midpoint of 8.75% ROE. Ameren Missouri is recommending a 10.90% ROE. This issue is addressed in detail in Section V of this report by Staff witness David Murray.

Fuel and Purchased Power net of Off System Sales – Issue Value – ($21 million difference). This difference relates to the different levels of fuel expense and off-system sales determined by Ameren Missouri and the Staff to be appropriate for the test year and the true-up period. The majority of this difference reflects the higher amount of off-system sales recommended by the Staff.

Payroll, Payroll Taxes and Benefits – Issue Value – ($10 million difference). This difference relates to the levels of employees. Staff has annualized the cost associated with the decline in employees at both Ameren Missouri and Ameren Services Company. This adjustment encompasses not only the increase in wage rates experienced by the Ameren Missouri, but also the employee level increases proposed by the Company for distribution training and staffing at the Sioux and Taum Sauk power plants.

Amortization Expense – Issue Value - ($13 million difference). This difference includes amortization expense associated energy efficiency, vegetation management, infrastructure inspections and other items.

Sioux Scrubbers – Issue Value - ($4.3 million difference). This difference reflects the Staff's disallowance of project cost.

There are other significant differences between the Staff and the Company, based upon their respective direct filings. However, these other differences are less significant than the items discussed above.

Staff Expert/Witness: (Section I, II, III and IV) Stephen M. Rackers

V. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula provided above is the rate of return (ROR), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital (WACC), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis. Staff's expert financial analyst, David Murray, has determined Ameren Missouri's cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, net of any risk adjustments, together with other capital component information as of March 31, 2010, to calculate Ameren Missouri's fair rate of return, as follows:

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.25%**	**8.75%**	**9.25%**
Common Stock Equity	50.92%	-----	4.20%	4.46%	4.71%
Preferred Stock	1.49%	5.189%	0.08%	0.08%	0.08%
Long-Term Debt	47.59%	5.944%	2.83%	2.83%	2.83%
Total	**100.00%**		**7.11%**	**7.36%**	**7.62%**

As contained in the above table, Staff recommends, based upon its expert analysis, a return on common equity (ROE) range of 8.25% to 9.25%, mid-point 8.75%, and an overall ROR of 7.11% to 7.62%, mid-point 7.36%. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-16. Additionally, with the exception of sources from which Staff simply extrapolated data and textbook references, supporting articles and/or reports are attached as Appendix 2, Attachments A - F. Staff will provide any additional supporting documentation upon the Commission's request.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory and by certain minimum Constitutional standards. Investor-owned public utilities such as Ameren Missouri are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the government must allow a reasonable opportunity for the shareholders to earn a fair return on their investment. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*, the Court stated:[1]

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

From these two decisions, Staff derives and applies the following principles to guide it in recommending a fair and reasonable ROR:

1. A return consistent with returns of investments of comparable risk;

2. A return sufficient to assure confidence in the utility's financial integrity; and

3. A return that allows the utility to attract capital.

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[1] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

Embodied in these three principles is the economic theory of the opportunity cost of investment. The opportunity cost of investment is the return that investors forego in order to invest in similar risk investment opportunities that vary depending on market and business conditions.

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[2] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return Ameren Missouri's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific Discounted Cash Flow (DCF) method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[3] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for Ameren Missouri.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model (CAPM). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial

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[2] Neither the DCF nor the CAPM methods were in use when those decisions were issued.

[3] Because the DCF method uses stock prices to estimate the cost of equity, this theory not only compares the utility investment to other utilities, but it compares the utility investment to all available assets. Consequently, setting the allowed ROE based on a market-determined cost of equity is necessarily consistent with the principles of ***Hope*** and ***Bluefield***.

integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***.

C. Current Economic and Capital Market Conditions

Determining whether a cost of capital estimate is fair and reasonable requires a good understanding of the current economic and capital market conditions, with the former having a significant impact on the latter. With this in mind, Staff emphasizes that an estimate of a utility's cost of equity should pass the "common sense" test when considering the broader current economic and capital market conditions.

1. Economic Conditions

The United States is emerging from the most severe recession since the Great Depression. Although the economy is now again expanding, economic growth is currently projected to be lower in the long-term as compared to the growth rates achieved during the post World War II era before the recent recession. Economists generally expect the long-term nominal Gross Domestic Product (GDP) growth rate to be in the range of 4% to 5%.[4] These projected long-term nominal GDP growth rates generally are predicated on 2% expected inflation, as measured by the GDP price deflator.

The Federal Reserve Bank (the Fed) continues to maintain the Fed Funds Rate at historically low levels between 0.00% and 0.25% (*see* Schedules 2-1 and 2-2). Additionally, the Fed made a unanimous decision in its recent meetings on January 25 and 26, 2011 to continue its bond buy-back program in order to provide continued liquidity to the financial system. According to a *Wall Street Journal* (*WSJ*) article[5], the Fed specifically stated that "the economic recovery is continuing, though at a rate that has been insufficient to bring about a significant improvement in labor market conditions." The Fed also stated that "longer-term inflation expectations have remained stable" and core inflation has been "trending downward." The Fed

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[4] The Congressional Budget Office (CBO), *The Budget and Economic Outlook: Fiscal Years 2011-2021,* January 2011; Minutes from the Federal Open Market Committee's ("FOMC") meeting on November 2-3, 2010; and The Livingston Survey, December 9, 2010.

[5] Sudeep Reddy, "Unanimous Fed Keeps Buying Bonds," *Wall Street Journal*, January 27, 2011, p. A5 (Attachment A).

stated that it expected to hold short-term interest rates at its current level for "an extended period," which many investors interpret as continuing until at least early 2012.

Consequently, while there is much debate regarding the effect current monetary policy may have on inflation, it appears that the Fed's primary concern is still the lack of sustainable growth in the economy. Additionally, although interest rates have increased in the last few months, it does not appear that this is due to the expectation of high inflation, at least based on interest rate differentials between Treasury Inflation Protected Securities (TIPS) and non-inflation protected Treasury bonds.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets continue to indicate a fairly low cost-of-capital environment. If one were to assume that the risk premium[6] required to invest in utility stocks rather than utility bonds was constant, then these lower utility debt yields clearly translate into a lower required return on equity. In other words, a lower cost of debt is indicative of a lower cost of capital, all else equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Although long-term interest rates, as measured by 30-year Treasury bonds (T-bonds), had decreased to the high 3 percent range during the months of July through October 2010, they have since increased to levels that were experienced from mid-2009 through mid-2010. (*see* Schedules 4-2 and 4-3). If 30-year T-bond yields persist at this level, then they will be more similar to the yields we experienced for most of the past decade, absent the credit crisis in late 2008 and early 2009.

Long-term utility bond yields have also continued to more closely track the changes in the 30-year T-bond yields in the last few months. For instance, long-term utility bond yields increased with 30-year T-bonds in the last two months of 2010. This was after reaching a 40-year low of approximately 5.10 percent in August and September of 2010. (*see* Schedules 4-1 and 4-3). As of December 2010, the average spread between 30-year

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[6] Risk Premium in this context is defined as the excess required return to invest in a company's equity rather than its debt.

T-bonds (4.42%) and average utility bond yields (5.61%)[7] was 121 basis points, which is 33 basis points below the average such yields displayed in the period since 1980 (*see* Schedule 4-4).

While the cost of investment-grade utility debt capital has reached historic lows, the risk premium required to invest in bonds of lower credit quality is higher than it was prior to the financial crisis of late 2008 and early 2009. Thus, while utilities with at least investment grade credit ratings can obtain capital quite cheaply, utilities with lower credit quality will pay a higher risk premium relative to risk-free rates than they did before the fall of 2008. However, the total required return on even borderline investment-grade debt is at levels more consistent with that realized during 2005, which was generally considered to be a period of “easy money.”

Some examples of the low cost of low-term debt involve recent issuances by The Empire District Electric Company (Empire). Empire recently capitalized on the lower cost of utility debt environment by issuing $50 million of 30-year First Mortgage Bonds at a coupon of 5.20%, which was used in part to redeem debt with a coupon of 7.05% maturing in 2022. Additionally, Empire was able to issue 10-year First Mortgage Bonds at the favorable rate of 4.65% last May, despite the fact that its S&P corporate credit rating of “BBB-” is only one notch above non-investment grade status.

b. Utility Equity Markets

For the twelve months ending December 31, 2010, the total return on the Dow Jones Industrial Average was 14.06%, the total return on the Standard & Poor’s 500 was 15.06%, and the total return on the Edison Electric Institute (EEI) Index of electric utilities was 7.04% (*see* Appendix 2, Attachment B). More specifically on a non-market capitalization weighted basis, the total return for the twelve months ending December 31, 2010 was 15.75% for EEI “Regulated” electric utilities, 8.51% for EEI “Mostly Regulated” electric utilities and -5.16% for “Diversified” electric utilities.

Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely

[7] The 5.61% yield is based on an average from data obtained from BondsOnline.com. For utility bond yields cited by Staff prior to December 2010, Staff used Mergent Bond Record.

to be more affected by general economic trends. The higher total return for "Regulated" electric utilities compared to broader markets and "Diversified" electric utilities implies that investors do not expect a significant economic recovery in the near future. Consequently, assuming investors in "Regulated" electric utilities have not increased their growth expectations for the regulated utility sector, these higher returns imply a decrease in the cost of equity for "Regulated" electric utilities.

A recent article, "The Latest Energy Deal Lacks Spark", published in the *Wall Street Journal* on January 11, 2011, confirms Staff's conclusions from the above-mentioned stock market data. The article generally discusses the proposed Duke Energy and Progress Energy merger:

> The stocks face another, paradoxical headwind: hope. Regulated utilities, with high, stable dividends, often are treated as bond proxies, a big reason for outperforming other utilities since early 2009. As broader optimism rises, however, so should debt yields, making regulated utility stocks relatively less attractive. Making them sexy again won't be easy when even a $13.7 billion merger doesn't set pulses racing.[8]

Consequently, while the decrease in bond yields has resulted in a decrease in the cost of equity for regulated utility companies, if bond yields should increase, then we should expect that the cost of equity for utilities should increase as well. However, in Staff's opinion the message is clear that recent declines in interest rates translate into low costs of equity for regulated utility companies.

D. Ameren's and Ameren Missouri's Operations

1. Ameren

The following excerpt from Ameren's Form 10-Q filing with the Securities Exchange Commission (SEC) for the quarterly period ended September 30, 2010 provides a good description of Ameren's current business operations and current organizational structure:

> Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. Ameren's primary assets are the common stock of its subsidiaries. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and

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[8] Liam Denning, "The Latest Energy Deal Lacks Spark," *The Wall Street Journal,* January 11, 2011, p. C18 (Attachment C).

liabilities. These subsidiaries operate, as the case may be, rate–regulated electric generation, transmission and distribution businesses, rate–regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries.

On October 1, 2010, Ameren, CIPS, CILCO, IP, AERG and Resources Company completed the previously announced two–step corporate reorganization. The first step of the reorganization involved CILCO and IP merging with and into CIPS, with CIPS as the surviving entity, pursuant to the terms of the agreement and plan of merger, dated as of April 13, 2010. Upon consummation of the merger, CIPS' name was changed to Ameren Illinois Company, or AIC, and the separate legal existence of CILCO and IP terminated. The second step of the reorganization involved the distribution of AERG stock from AIC to Ameren and the subsequent contribution by Ameren of the AERG stock to Resources Company. The AIC Merger was accounted for as a transaction between entities under common control. In accordance with authoritative accounting guidance, assets and liabilities transferred between entities under common control were accounted for at the historical cost basis of the common parent, Ameren. The AERG distribution was accounted for as a spin–off. AIC transferred AERG to Ameren based on AERG's carrying value. See Note 14 – Corporate Reorganization for additional information. Throughout this document we continue to reference CIPS, CILCO and IP when discussing historical results. When discussing current or future operations or results, we reference the newly merged entity, AIC.

Ameren's principal subsidiaries as of September 30, 2010, are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report.

• UE, or Union Electric Company, operates a rate–regulated electric generation, transmission and distribution business, and a rate–regulated natural gas transmission and distribution business, all in Missouri.

• CIPS, or Central Illinois Public Service Company, operates a rate–regulated electric and natural gas transmission and distribution business, all in Illinois. Effective October 1, 2010, CIPS changed its name to Ameren Illinois Company, or AIC.

• Genco, or Ameren Energy Generating Company, operates a merchant electric generation business in Illinois and Missouri. Genco has an 80% ownership interest in EEI.

• CILCO, or Central Illinois Light Company, operated a rate–regulated electric transmission and distribution business, a merchant electric

> generation business through AERG, and a rate–regulated natural gas transmission and distribution business, all in Illinois.
>
> • IP, or Illinois Power Company, operated a rate–regulated electric and natural gas transmission and distribution business, all in Illinois.
>
> Ameren has various other subsidiaries responsible for the marketing of power, procurement of fuel, management of commodity risks, and provision of other shared services.

It is Staff's understanding that Ameren's recent restructuring is not expected to directly impact the organizational structure, financing and/or capital structure of Union Electric.

2. Ameren Missouri

In Note 1 to Ameren's Notes to Financial Statements, Ameren provides the following description of Ameren Missouri's operations:

> UE, or Union Electric Company, also known as AmerenUE, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri. UE was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the state of Missouri. It supplies electric and gas service to a 24,000-square-mile area located in central and eastern Missouri. This area has an estimated population of 2.8 million and includes the Greater St. Louis area. UE supplies electric service to 1.2 million customers and natural gas service to 126,000 customers.

Ameren has simply made a "doing business as" ("dba") name change for the UE properties. UE is now referred to as "Ameren Missouri" rather than "AmerenUE." It is Staff's understanding that Ameren made this "dba" name change in order to communicate to the public that the UE properties only consist of Missouri gas and electric utility properties.

E. Ameren Missouri's and Ameren's Credit Ratings

Ameren and Ameren Missouri are currently rated by Moody's, Standard & Poors (S&P) and Fitch. It is important to understand the current credit standing of Ameren as well as Ameren Missouri, as Ameren's ratings influence investors' views of the risk associated with investing in Ameren Missouri. Although Staff is not estimating the cost of capital for Ameren in this case, the influence of the risks of Ameren's other operations, which includes non-regulated merchant generation operations, on Ameren Missouri's risk must be understood in order to estimate a fair rate of return for Ameren Missouri.

Ameren Missouri's Moody's, S&P and Fitch issuer/corporate credit rating are 'Baa2', 'BBB-', and 'BBB+', respectively. Ameren's Moody's, S&P and Fitch issuer/corporate credit rating are 'Baa3', 'BBB-', and 'BBB', respectively.[9] Moody's and Fitch rate Ameren one notch lower than Ameren Missouri because Moody's and Fitch tend to give more weight to the stand-alone financial risk and business risk of the subsidiary, i.e. they view Ameren Missouri's credit quality as being stronger than that of the parent. However, S&P's ratings methodology is based on its view that without significant ring-fencing mechanisms in place, they will rate the subsidiary based on the consolidated credit quality of the parent company. In fact, S&P does not even publish an analysis of the Ameren Missouri's stand-alone financial ratios. S&P only provides the financial ratios of Ameren.

The following is an excerpt from a December 28, 2010, S&P credit-rating report on Ameren Missouri:

> The ratings on Ameren Missouri reflect Ameren Corp.'s (Ameren) consolidated credit profile. The ratings also reflect Ameren Missouri's excellent business risk profile and Ameren's consolidated significant financial risk profile. Ameren's subsidiaries include rate regulated utilities Ameren Illinois and Ameren Missouri, and merchant energy company AmerenEnergy Generating Co. (GenCo.) As of Sept. 30, 2010, Ameren had about $7.7 billion of total debt outstanding. Based on the combination of future earnings, cash flow, capital expenditures, and credit risk exposure, we view Ameren as about 75% regulated and 25% merchant generation.
>
> Ameren Missouri's excellent business risk profile reflects its recent rate cases and regulatory mechanisms that overall indicate a decreasing regulatory risk. Ameren Missouri is a rate-regulated utility that serves 1.2 million electric and 126,000 gas customers in portions of central and eastern Missouri. The company also has 10,400 megawatt (MW) of generating capacity of which 5,400 MW is base load coal and 1,200 MW is nuclear generation. In 2009 and 2010, the company received credit supportive rate case orders from the Missouri Public Service Commission that includes more than $390 million of base rate increases, a fuel adjustment clause, pension and OPEB trackers, and a cost tracker for vegetation management and infrastructure inspections. Recently, the

[9] Ameren's SEC Form 10-Q Filing for the period ended September 30, 2010, p. 101.

> company filed for a $12 million gas revenue increase and a $263 million electric rate increase. The commission's orders for the gas and electric rate cases are expected by April 2011 and July 2011, respectively. We expect that Ameren Missouri will continue to file rate cases on a frequent basis to reduce its regulatory lag.
>
> Ameren's consolidated satisfactory business risk profile reflects the combination of the excellent business risk profiles of Ameren's regulated businesses offset by the fair business risk profile of Ameren's merchant energy businesses.

As clearly explained in the above excerpt from S&P's ratings analysis of Ameren Missouri, Ameren's non-regulated businesses hinder the ability of Ameren Missouri to achieve a higher credit rating from S&P. Although there is no consensus among the rating agencies on how much of an impact Ameren's non-regulated operations have on Ameren Missouri's credit quality, there is likely to be some trickle-down effect on Ameren Missouri's cost of capital due to its affiliation with these higher risk enterprises. However, Staff does not currently propose any downward adjustment to Ameren Missouri's cost of debt to reflect this trickle-down effect because the amount of the impact is debatable due to differing views on credit quality and the fact that there is currently only a one notch difference between Ameren's and Ameren Missouri's Moody's and Fitch credit rating. Although Staff did not make a downward adjustment to Ameren Missouri's cost of debt, Staff is not proposing to make an upward adjustment to the proxy group's cost of equity due to the credit rating differential between Ameren and Ameren Missouri as they compare to the average for the proxy group, due to the Staff's concerns discussed above.

F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an appropriate ratemaking capital structure, (2) the Company's embedded cost of debt and preferred stock, and (3) the Company's cost of common equity.

1. Capital Structure

Schedules 5-1 and 5-2 present Ameren Missouri's and Ameren's historical capital structures in dollar terms and percentage terms, respectively, for the past five years. As can be derived from these historical capital structures, the current capital structure of Ameren Missouri is fairly consistent with the way in which Ameren has been capitalized over this period, easing any concerns Staff may have regarding manipulation of Ameren Missouri's capital structure for ratemaking purposes.

Staff did discover that Ameren Missouri has not issued any short-term debt for at least up to 13 months since September 2009. This is the case in spite of the fact that Ameren Missouri had a construction work in progress (CWIP) balance of approximately $1 billion as of December 31, 2009. Although Staff decided to exclude short-term debt from its recommended ratemaking capital structure for purposes of its direct filing, Staff will continue to investigate this issue during the course of this case to determine if any adjustments should be made to consider the higher capital costs associated with Ameren's decision to infuse significant amounts of cash into Ameren Missouri through long-term financings.

For the purposes of its direct case, Staff accepted the Ameren Missouri capital structure provided in the Direct Testimony of Company witness Michael G. O'Bryan (*see* Schedule MGO-G1). The capital structure is as of the end of the test year period ending March 31, 2010. Schedule 6 presents Ameren Missouri's capital structure and associated capital ratios. The resulting capital structure consists of 50.92 percent common stock equity, 1.49 percent preferred stock and 47.59 percent long-term debt.

2. Embedded Cost of Debt and Preferred Stock

Staff also accepted the embedded cost of long-term debt and preferred stock provided in the Direct Testimony of Company witness Michael G. O'Bryan (*see* Schedule MGO-G2 and Schedule MGO-G4).

3. Cost of Common Equity

Staff witness, David Murray determined Ameren Missouri's cost of common equity through a comparable company cost-of-equity analysis of a proxy group of 10 companies using the DCF method. Additionally, Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 58 market-traded electric utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to Ameren Missouri's regulated electric utility operations (*see* Schedule 7):

1. Classified as an electric utility by Value Line (58 companies);
2. Publicly-traded stock;
3. Followed by EEI and classified by EEI as a regulated electric utility (23 companies eliminated, 35 remaining);
4. Followed by AUS and reporting at least 70% of revenues from electric operations (9 companies eliminated, 26 remaining);
5. Ten years of Value Line historical growth data available (3 companies eliminated, 23 remaining);
6. No reduced dividend since 2007 (5 companies eliminated, 18 remaining);
7. Projected growth available from Value Line and Reuters (2 companies eliminated, 16 remaining);
8. At least investment grade credit rating (2 companies eliminated, 14 remaining);
9. Company-owned generating assets (2 companies eliminated, 12 remaining); and
10. Significant merger or acquisition announced in last 3 years (2 companies eliminated, 10 remaining).

This final group of 10 publicly-traded electric utility companies ("the comparables") was used as a proxy group to estimate the cost of common equity for Ameren Missouri's regulated electric utility operations. The comparables are listed on Schedule 8.

b. The Constant-growth DCF

Next, Staff calculated Ameren Missouri's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[10] [11] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the 2011 Value Line projected dividend per share (*see* Schedule 11) by the monthly high/low average stock price for the three months ending December 31, 2010 (*see* Schedule 10).[12] Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.5%, unadjusted for quarterly compounding.

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate (g) that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share (DPS), earnings per share (EPS) and book value per share (BVPS) for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to

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[10] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 195-196.

[11] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p.64.

[12] The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P0 is calculated by averaging the highest and the lowest price for each month during the selected period.

be quite volatile.[13] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 9-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 9.50%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 8.00%. The average projected 5-year EPS estimates yielded a growth rate of 6.03%, which Staff believes is not sustainable (*see* Schedule 9-4, Column 6).

Due to the current volatility and wide dispersions present in Staff analysis of historical and projected DPS, EPS, and BVPS, Staff considered none of those methods to produce reliable indicators of long-term growth expectations. For this reason, Staff selected an alternative input, based upon Staff's expertise and understanding of current market conditions. Staff used a growth rate range of 4.0% to 5.0% in its constant-growth DCF, although Staff does not consider that figure to be sustainable for the electric utility industry in the long run. According to data published in the *2003 Mergent Public Utility and Transportation Manual,* electric utility growth rates have been approximately half of achieved GDP growth for the period 1947 through 1999.[14] As noted previously, long-term GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities should be much lower than the projected 5-year EPS growth rates.

Staff also analyzed the growth of electric utilities identified by Value Line as *Central* region electric utilities over the period 1968 through 1999, a shorter, more recent period based on data from Value Line rather than Mergent (Staff will explain this analysis in more detail when explaining its multi-stage DCF analysis). Staff's analysis of this data revealed that the actual realized growth of these electric utilities was less than *half* of GDP growth over this time period. In addition, this analysis also showed that during a period of much higher nominal GDP growth, the *Central* region electric utilities' EPS, DPS and BVPS grew in the range of 3.18% to 3.99% (*see* Schedules 13-1 through 13-4). Because the constant-growth DCF will only provide reliable results if the growth rate is within 1.0% to 2.0% of a sustainable long-term industry growth

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[13] Schedule 9-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 9-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

[14] 2003 Mergent *Public Utility &* Transportation *Manual*, p. a15 – a18.

rate[15], Staff decided its analysis of historical growth in the electric utility industry could only marginally support a more aggressive growth rate range of 4.0% to 5.0%. Staff emphasizes that it believes this growth rate is probably higher than what investors expect for the electric utility industry considering that expected long-term GDP growth is approximately 4.5%. For this reason, Staff places primary weight on its multi-stage DCF analysis.

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 4.5% and a growth rate range of 4.0% to 5.0% -- Staff has estimated Ameren Missouri's cost of common equity to be 8.5% to 9.5% (*see* Schedule 11).

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[16] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for Ameren Missouri.

A multi-stage DCF may use either two or three growth stages, depending on the situation being modeled. In either case, the last stage must use a sustainable rate as it is considered to last into perpetuity. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate estimate for the final stage because this rate is assumed to last in perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[17]

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[15] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 193.

[16] Dr. Aswath Damadoran, Professor of Finance of the New York University Stern School of Business, advocates using a multi-stage methodology if the constant-growth rate is expected to be 1-2% different than the earlier stage growth rates. Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 193.

[17] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 71-72.

In the present case, Staff used a three-stage DCF approach, the stages being years 1-5, years 6-10, and years 11 to infinity.[18] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 12-1 through 12-3). Based on this set of assumptions, Staff's estimated cost of equity for the proxy group is approximately 8.40% to 9.15%, mid-point of 8.775%. Using the mid-point of Staff's assumed range of perpetual growth rates results in an estimated cost of equity of approximately 8.75%.

ii Stage one

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for purposes of estimating the growth in DPS in a single-stage constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analysis should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

[18] In practice, Staff extended the third stage only to year 200.

iii. Stage two

Stage two, i.e. the transition stage, is simply a gradual movement from above normal growth to more normal/sustainable growth for the final stage. Although stage two can also consist of forecasted discrete cash flows, because it is a transitional period, it is logical to linearly reduce the high growth first-stage growth over a specific period in order to gradually reduce the growth rate to the expected sustainable growth rate. Staff chose to do this over a five year period, which is fairly conventional in multi-stage DCF analysis.

iv. Stage three

Stage three is the final/constant-growth stage. In fact the final stage can be reduced to the single-stage, constant-growth form of the DCF. Although this is the "generic" stage, it is extremely important to select a reasonable growth rate for this stage to arrive at a reliable cost of equity estimate.

Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. Consequently, Staff will explain in further detail Staff's assumed perpetual growth rate range of 3.00% to 4.00% and will test this perpetual growth rate for reasonableness.

v. Electric Utility Industry Long-term Growth Rates

In the last AmerenUE rate case, Staff estimated the perpetual growth rate based on expected long-term growth in demand for electricity plus an expected inflation factor. Although Staff still considers this to be a sound approach and consistent with how investors evaluate growth expectations, the Commission's *Report and Order* in the last AmerenUE rate case, Case No. ER-2010-0036, indicated that the Commission believed this approach was inconsistent with the requirements of the DCF methodology because it does not directly consider EPS and/or DPS growth. Consequently, Staff researched additional data to estimate an electric utility industry long-term average EPS, DPS and BVPS growth rate.

In testimony in the current Kansas City Power & Light Company (KCPL) and KCP&L Greater Missouri Operations Company (GMO) rate cases, File Nos. ER-2010-0355 and ER-2010-0356, respectively, Staff provided historical electric utility growth information published in the 2003 Mergent *Public Utility and Transportation Manual* to show that a long-term electric utility growth rate shouldn't be any higher than 3% to 4%. However, in responding to concerns raised by KCPL's and GMO's ROR witness about this data in those cases, Staff was not able to replicate the Mergent data. Consequently, Staff decided to perform its own study of long-term growth in per share data for a proxy group of electric companies (see Schedules 13-1 through 13-4).

The Financial Analysis Department has access to Value Line data on *Central* region electric utility companies dating back to 1968.[19] Although Staff has access to current electric utility financial data for all regions of the United States (*Central, East* and *West*), Staff's access to older data from the *East* and *West* regions is limited. Staff believes it is important to analyze electric utility industry financial data to at least the early 1970s since this was approximately the beginning of the last large construction cycle for the electric utility industry.[20] Because 1968 is consistent with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc. bankruptcy in December 2001. Considering that much of this disruption was caused by deregulation, Staff does not consider the information during this period to be informative for understanding investors' growth expectations for regulated electric utility operations.

Staff did not apply rigid selection criteria for purposes of selecting central electric utility companies contained in Edition 5 of the Value Line Investment Survey. However, Staff did eliminate companies that generally did not have at least 70% of revenues from electric utility operations in the late 1990s. Staff also eliminated companies that appeared to be impacted significantly by restructuring in anticipation of the restructuring of the electric utility markets in

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[19] Value Line has consistently published information the electric utility industry based on three regions: East, West and Central. The Central Region electric utility industry data is published in Edition 5 of The Value Line Investment Survey data. Staff maintained consistent and comprehensive files for the Central Region for reports published back to 1985, which provides electric utility per share data dating back to 1968.

[20] Daniel Ford, Gregg Orrill, Theodore W. Brooks, Ross A. Fowler, M. Beth Straka and Noah Howser, "Utilities Capital Management," July 16, 2009, Barclays Capital, p. 13 (Attachment D).

the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major mergers, acquisitions and/or restructurings. Staff only included companies in which comparable data was available for each year of the period 1968 through 1999. The companies Staff selected are shown in Schedules 13-1 through 13-4.

Staff's analysis of these electric utility companies' data over the last electric utility construction cycle indicates that average long-term growth slowly increased through the late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on Staff's calculation of a simple average of all of the companies' growth rates over this period. Because a simple average gives each company equal weight, Staff believes this approach is appropriate because it does not introduce size bias. As can be seen in the attached Schedules, the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth rate was 3.18%; and the overall average for DPS, EPS and BVPS was 3.59%.

However, it is important to understand that these growth rates were achieved during a much more robust economic environment than the U.S. is expected to achieve in the foreseeable future. Also, it is interesting to note that the average growth rate for these electric utilities was less than 50% of GDP growth over the same period.

Also attached is Staff Schedule 15, which shows Staff's study of actual realized long-term growth of electric utility companies for the period 1947 through 1999 as published in the 2003 Mergent *Public Utility and Transportation Manual.* Although Staff was not able to replicate this data in the current KCPL and GMO rate cases, Staff believes this information is still useful in evaluating the trends in growth rates for the electric utility industry. This data also demonstrates that electric utility companies do not grow at the same rate as GDP over the long-term.

vi. Perpetual Growth Rates Used in Investment Analysis

Goldman Sachs generally assumes a perpetual growth rate of 2.5% when performing a DCF analysis of regulated electric utility companies (*see* Appendix 2, Attachment E, p. 21).[21]

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[21] Michael Lapides, Zac Hurst and Jadieep Malik, *Company Update: Great Plains Energy*, "Financing NT needs outweigh valuation on normalized LT earnings," March 2, 2009, p. 6.

If Staff had assumed a perpetual growth rate of approximately 2.5% in its multi-stage DCF analysis, Staff's estimated cost of equity would have been approximately 8.05%.

It is also noteworthy that Goldman Sachs' analysis compares the growth of electric utility demand to that of changes in real GDP growth. According to Goldman Sachs, typically a 1% change in real GDP growth causes a 0.6% to 0.7% change in electricity demand. Clearly this contradicts the theory that electric utilities' cash flows should be able to grow at the same rate of economic growth. Although there may be short-term issues that cause a lower or higher growth rate than that driven by demand growth, these issues will not be sustainable. Therefore, it is appropriate to consider this information when determining investors' expectations of long-term sustainable growth and whether it is plausible to expect electric utilities to grow at the same rate of GDP.

Based on all of the aforementioned information, Staff's assumed perpetual growth rate range of 3% to 4% is reasonable and consistent with what investors use in practice.

vii. Commission Preference for GDP Growth

Finally, although Staff does not believe the use of long-term GDP growth is an appropriate proxy for the perpetual growth rate for electric utilities, Staff does recognize that the Commission indicated a preference for this proxy in its *Report and Order* in File No. ER-2010-0036. In this *Report and Order* the Commission stated a preference to use historical GDP growth from 1929 through 2008 to derive an expected growth rate of 6.0% for the economy. Although Staff does not recommend the Commission use GDP as a proxy for perpetual growth in this case, if the Commission should choose to do so, Staff advises the Commission to use growth rates that are consistent with long-term projections for GDP growth in the current economic environment. This growth rate would be approximately 4.5% based on various projections available. If Staff makes this assumption in its multi-stage DCF analysis, then the estimated cost of equity is approximately 9.50%.

G. Tests of Reasonableness

Staff has tested the reasonableness of its DCF results, both by use of a CAPM analysis and consideration of other evidence.

1. The CAPM

The CAPM is built on the premise that the variance in returns is the appropriate measure of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks, also called market risks, are unanticipated events that affect almost all assets to some degree because the effects are economy wide. Systematic risk in an asset, relative to the average, is measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are unanticipated events that affect single assets or small groups of assets. Because unsystematic risks can be freely eliminated by diversification, the reward for bearing risk depends on the level of systematic risk. The CAPM shows that the expected return for a particular asset depends on the pure time value of money (measured by the risk free rate), the reward for bearing systematic risk (measured by the market risk premium), and the amount of systematic risk (measured by Beta). The general form of the CAPM is as follows:

$$k = Rf + \beta \, (Rm - Rf)$$

Where:	k	is the expected return on equity for a security;
	Rf	is the risk-free rate;
	β	is Beta; and
	Rm - Rf	is the market risk premium.

For inputs, Staff relied on historical capital market return information through the end of 2010. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending December 31, 2010; that figure was 4.16%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 15). The average beta (β) for the proxy group was 0.66. For the market risk premium (Rm – Rf), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.[22] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2009, which was 6.00%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2009, which was 4.40%.

[22] From Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2010 Yearbook.*

Staff's CAPM is presented on Schedule 12. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 8.09% and 7.04%, respectively. These low cost of common equity results support the reasonableness of Staff's higher cost of equity estimates from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 7% to 8% range for utility stocks.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity (YTM) of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4% range.[23] Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of October, November and December 2010, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 5.24% and 5.82% respectively.[24] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 8.24% and 8.82%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 9.24% and 9.82%.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using the average authorized returns published by Regulatory Research Associates (RRA) as a benchmark. According to RRA, (*see* Appendix 2, Attachment F), the average authorized cost of common equity for electric utility companies for the for 2010 was 10.34% based on 59 decisions (first quarter – 10.66% based on seventeen decisions; second quarter – 10.08% based on

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[23] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p. 54.

[24] BondsOnline.com pursuant to a subscription agreement Staff has with BondsOnline.

fourteen decisions; third quarter – 10.26% based on eleven decisions; fourth quarter – 10.30% based on seventeen decisions). The average authorized cost of common equity for electric utility companies for 2009 was 10.48% based on 39 decisions (first quarter – 10.29% based on nine decisions; second quarter – 10.55% based on ten decisions; third quarter – 10.46% based on three decisions; fourth quarter – 10.54% based on seventeen decisions).

The average authorized ROR for electric utilities for 2010 was 7.99% based on 59 decisions (first quarter – 7.95% based on seventeen decisions; second quarter – 7.95% based on fifteen decisions; third quarter – 8.16 based on twelve decisions; fourth quarter – 7.95% based on fifteen decisions). The average authorized ROR for electric utilities in 2009 was 8.23% based on 38 decisions (first quarter – 8.19% based on eight decisions; second quarter – 8.05% based on nine decisions; third quarter – 8.48% based on three decisions; fourth quarter – 8.30% based on eighteen decisions).

Additionally, Staff's recommended ROR is below the average authorized RORs, which is probably a function of both Staff's lower cost of equity estimate and the Ameren Missouri's lower embedded cost of debt than other electric companies that may be included in the allowed ROR averages.

While Staff understands the Commission's desire to review other commissions' authorized ROE's due to concerns about Missouri-jurisdictional utilities having to compete with other utilities for capital, Staff would like to briefly explain why an allowed ROE is not indicative of a required ROE and the ability to attract capital. The primary consideration for attraction of capital is whether the current price of a given stock will result in the investor earning above, below or equivalent to their required return. For example, the allowed ROEs for many of Southern Companies' utility subsidiaries are typically much higher than the rest of the utilities in the country. However, this does not translate into higher realized returns for investors in Southern Company because the price of Southern Company's stock already reflects these high allowed ROEs. If this Commission were to award an ROE similar to those allowed for Southern Company's subsidiaries and hold all other ratemaking treatments constant, then current investors in the Missouri utility would achieve a return that was higher than their required return. However, after the increase in the Missouri utility's stock price, the investor and subsequent prospective investors would revert back to earning their required return. The opposite holds true if the Commission were to authorize an ROE below what is expected from the Commission.

Consequently, setting allowed ROEs based on those allowed or earned for other companies may temporarily cause upward or downward pressure on the stock, but once this price correction occurs, the stock should experience "normal" capital attraction.

H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover Ameren Missouri's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for Ameren Missouri in the range of 7.11% to 7.62% (*see* Schedule 16). This rate was calculated by applying an embedded cost of long-term debt of 5.94% and a cost of common equity range of 8.25% to 9.25% to a capital structure consisting of 50.92% common equity, 47.59% long-term debt, and 1.49% preferred stock. Staff urges the Commission to accept its recommendation and in order to allow Ameren Missouri to earn a fair return on its net rate base.

Staff Expert/Witness: David Murray

VI. Rate Base

A. Plant in Service and Depreciation Reserve

1. Plant in Service

a. Accounting Schedule 3

This Schedule has been adjusted, by account, to reflect the rate base value of Ameren Missouri's plant in service estimates through February 28, 2011. The Staff adjusted Ameren Missouri's plant balances to allocate a portion of the Company's general plant to Ameren Missouri's retail natural gas business. These adjustments to the March 31, 2010 test year balances are reflected in Adjustments to Plant - Accounting Schedule 4.

Staff Expert/Witness: Lisa M. Ferguson

b. Government Relocations Construction Accounting

Ameren Missouri owns and operates facilities which are located in public and private rights-of-way. If a government entity requests that the Company move these facilities, for example to widen a highway, Ameren Missouri is required to comply. However, based on the response to Staff Data Request No. 162, a majority of the time the Company is notified of a pending project within 6 months of when the project is to begin. In addition, governmental agencies are usually very understanding when Ameren Missouri must delay relocation work for emergency responses to accidents or storms, as well as due to unknown, hidden underground obstructions. If facilities must be de-energized before performing relocation work, the project may also be delayed due to changes in load caused by weather or emergencies. Therefore, Ameren Missouri is able to exercise significant control over when the government relocation work is performed.

Ameren Missouri has a detailed process for estimating both the cost and performance date of relocation work, including contact/notice, negotiations, timelines/scheduling, Company discretion, problem resolution, inspection, monitoring and final approval. In addition, although most relocation work is performed in public rights-of-way and at the Company's expense, if Ameren Missouri facilities are located on private property, the governmental entity must reimburse the Company for the relocation project at its cost. Government relocation of the Company's facilities is an established routine function of Ameren Missouri.

During the period 2001 through 2009, Ameren Missouri incurred net capital additions, on average, of approximately $7 million per year due to government relocations. However, the amount in any one year has ranged from approximately $0 (zero) to $11.8 million. In contrast, during those same nine (9) years Ameren Missouri's total plant in service has increased, on average, by approximately $400 million per year. Government relocations are an extremely small portion of the Company's ongoing construction program.

The Commission has ordered the specific true-up cut-off date of February 28, 2011 in this case for considering changes in each of the cost of service components, including revenues, expenses and investment. It would be inappropriate to consider in isolation changes in only one item, such as costs caused by government-requested relocations of facilities, while not considering potentially offsetting changes in the other cost of service components.

Based on the above considerations, the Staff is not proposing any special ratemaking treatment for government-requested relocations of facilities, special ratemaking treatment such as continuing construction accounting, where Ameren Missouri is allowed to continue to accrue accumulated funds used during construction (AFUDC) and defer depreciation expense until the related investment was included in cost of service for setting rates. In addition, based on Ameren Missouri's response to Staff Data Request No. 274, the Company has not performed any analysis that examines, discusses, calculates the value of, or determines the effect on earnings of continuing construction accounting for government-requested relocations of facilities.

Staff Expert/Witness: Stephen M. Rackers

c. Other Plant Construction Accounting

The Commission has ordered the specific true-up cut-off date of February 28, 2011 for considering changes in all the cost of service components in this case, including revenues, expenses and investment. It would be inappropriate to consider in isolation changes in only one item, such as continued construction accounting for an indefinite period on plant closings for an additional five months beyond the true-up cut-off date, while not considering potentially offsetting changes in the other cost of service components.

Offsetting changes in other components of the cost of service directly related to the plant additions include increases in the depreciation and deferred income tax reserves and decreases in depreciation expense for plant retirements due to the plant additions. Although construction accounting allows depreciation expense to be deferred, the reserve begins to accumulate, and the deferred income tax reserves will also begin to accumulate. The depreciation on the plant retired in connection with the plant additions will decrease depreciation expense. All three of these items are standard reductions to the cost of service.

Offsetting changes in other components of the cost of service not directly related to the plant additions include such items as accumulating depreciation and deferred income tax reserves on existing plant, increased revenues for additional customer growth, and reductions in expenses due to proactive cost cutting measures taken by the Company.

In 2010 Ameren Missouri's plant in service increased by approximately $175 million, excluding Taum Sauk, during the five-month period of March through July. Continuing AFUDC at the rate of 5% and deferring depreciation at the rate of 2.5% accumulates to approximately

$20 million after eighteen months. As discussed above, Ameren Missouri's plant in service has increased, on average, by $420 million per year.

As a result of the above discussion, the Staff is not proposing any special ratemaking treatment for plant additions that occur after the true-up cut-off date of February 28, 2011, special ratemaking treatment such as continuing construction accounting until the related investment is included in rates. In addition, based on Ameren Missouri's response to Staff Data Request No. 273, the Company has not performed any analysis that examines, discusses, calculates the value of, or determines the effect on earnings of continuing construction accounting for other plant additions.

Staff Expert/Witness: Stephen M. Rackers

d. Sioux Units 1 and 2 Scrubber In-Service

Sioux Units 1 and 2 are cyclone-furnace, coal-fired generating units located in St. Charles County, Missouri.

Staff and Ameren Missouri previously agreed on a set of in-service criteria to verify that the Sioux scrubbers were fully operational and used for service, and should be considered for inclusion in rate base.

Scrubbers were installed on Sioux Units 1 and 2 to remove SO2 from the unit's emissions. The specific criteria and Staff's evaluation notes are attached as Appendix 3, Schedule MET-1 to this report. Based on Staff's on-site observations of the units, supplemented by review of test records, computer data, and other documentation, the Staff concludes that the scrubbers successfully met all of the in-service criteria and were fully operational and used for service at the completion of in-service testing data collection, which occurred on November 23, 2010.

Staff Expert/Witness: Mike E. Taylor

e. Taum Sauk Rebuild In-Service Test Criteria

As part of Staffs' monitoring of the rebuild of the upper reservoir criteria were developed to assure and verify the Taum Sauk Power station was capable and available for commercial service. The objectives of these criteria are to establish that the units are capable and durable. Capability is determined by the units' demonstrated ability to meet specific pump/generation requirements as stated in the criteria. Durability is demonstrated by the units sustaining specific periods of pump/generation as stated in the following criteria.

1. All major construction for the upper reservoir to be considered for inclusion in rate base shall be completed.
2. All preoperational tests for the upper reservoir to be considered for inclusion in rate base shall be completed. The BOC Appendix G the Reservoir Refill Program addresses these specific criteria.
3. Units have operated at several different reservoir levels and delivered power output near or in excess of anticipated output based on guaranteed power curve while vibrations are within design limits. Confirm that each of the units being evaluated did not exhibit any unusual vibration outside of design specification requirements.
4. Units successfully meet all contract operational guarantees.
5. Units successfully demonstrates its ability to initiate the proper start sequence resulting in the unit operating from zero (0) rpm (or turning gear) to full load when prompted at a location (or locations) from which it is normally operated.
6. Units successfully demonstrates its ability to initiate the proper shutdown sequence from full load resulting in zero (0) rpm (or turning gear) when prompted at a location (or locations) from which it is normally operated.
7. Units successfully demonstrates its ability to operate at minimum load for one (1) hour.
8. Units successfully demonstrate its ability to operate at or above 95% of nominal capacity for 4 continuous hours.
9. Units successfully demonstrates its ability to produce an amount of energy (MWhr) within a 72 hour period that results in a capacity factor of at least 50% during the period when calculated by the formula: capacity factor = (MWhrs generated in 72 hours) / (nominal capacity x 72 hours).

As part of the verification process the Staff engineers visited the Taum Sauk Power Station to observe operation of the units on April 15, 2010. The Company later provided written documentation and operational logs in the form of a tabbed note book indicating the units had met each of the operational criteria. As a final review Staff again visited the site to observe pump/generation cycling of the units on August 20, 2010. Based on its review Staff recommends the Commission declare Taum Sauk Power Station "fully" operational and used for service.

Staff Expert/Witness: Guy C. Gilbert, MS, PE, RG

2. Depreciation Reserve - Accounting Schedule 5

Accounting Schedule 5, Depreciation Reserve, has been adjusted by account, to reflect the rate base value of Ameren Missouri's depreciation reserve estimate through February 28, 2011. As it did with Plant in Service, the Staff adjusted Ameren Missouri's depreciation reserve balances to allocate a portion of the Company's general plant depreciation reserve to Ameren Missouri's retail natural gas business. These adjustments to the March 31, 2010 test year balances are reflected in Adjustments to Depreciation Reserve - Accounting Schedule 6.

Staff Expert/Witness: Lisa M. Ferguson

B. Cash Working Capital (CWC)

1. Calculation of Revenue and Expense Lags

In certain instances, after examining the appropriateness of the calculations, the Staff has used the same revenue and expense lag factors as those recommended by the Company. In certain other situations, the Staff determined that the lag Ameren Missouri calculated was not appropriate. In these instances, the Staff developed a new lag based on different or updated information from the current case, if it was determined that a new lag was more appropriate. For example, the Company developed its revenue collection lag using accounts receivable aging reports. However, the Staff used a report specifically maintained for rate cases that calculates the actual period of time the customers take to pay their bills. This report has been used by both the Staff and the Company to determine the revenue collection lag in previous rate cases. In the Staff's opinion the report it used accurately measures how long customers take to pay their bills.

Staff Expert/Witness: Lisa M. Ferguson

2. Differences Between Staff's and Company's Calculation of CWC

There were several items that Staff calculated differently than Company. First, Staff determined different expense lags for Pensions and Other Post Retirement Benefit Costs' (OPEBs) due to updated payment dates and amounts that were provided by the Company. Company determined that vacation payroll would be a negative amount, but when Staff calculated this item based on the response to Data Request No. 0208, a positive $958,299 was determined. Company also calculated a 27.59 day expense lag on Gross Receipts Taxes. While the frequency of payment depends on the municipality to which the payments are being made. Payments are made on the last day of the following month, or for some cities, the 20th day of the following month. With these payment policies in mind, Staff calculated a 48.09 day expense lag for Gross Receipts Taxes.

Company and Staff also differed in regard to some components of the revenue lag. The first difference is reliance on different reporting for the calculation of the collection lag as previously discussed. The second component is the non-inclusion of the payment processing lag. Ameren Missouri includes an addition to the revenue lag for the time it takes to process the customer's payment for deposit. In the Staff's opinion, a similar lag exists on the expense side when vendors process payments from Ameren Missouri. However, the Company has not increased the expense lag to capture this period. The Staff recommends that processing lags not be included in the determination of cash working capital. An additional difference between the Company and the Staff exists regarding pass-through taxes. The Staff has eliminated the payment lag on both sales and gross receipts taxes since the Company provides no service until the tax is added to the customer's bill. The Company recognizes this reduced revenue lag for gross receipts taxes, but not sales taxes.

The Staff has included a separate line item for the payments made by Ameren Missouri to the decommissioning trust fund for the Callaway Nuclear Plant. The average lag associated with these payments is 68.75 days.

Staff Expert/Witness: Lisa M. Ferguson

C. Prepayments, and Materials and Supplies

The Company has utilized shareholder funds for prepaid items such as insurance premiums and materials and supplies. By including these items in rate base, this up-front investment made by the Company is recognized in customers' rates. The Staff has included prepayments in rate base at the 13-month average level ending March 31, 2010.

The Company also maintains a variety of materials and supplies in inventory to meet its day-to-day needs in performing its utility operations. The Staff has included Ameren Missouri's average balance of materials and supplies inventory that was maintained during the 13 months ending March 31, 2010. The level of both materials and supplies and prepayments will be reexamined as part of the Staff's true-up.

Staff Expert/Witness: Lisa M. Ferguson

D. Fuel Inventories

Staff included a 13-month average of coal inventory through November 30, 2010 adjusted to reflect coal prices that will be in effect as of February 28, 2011. Staff also utilized 13-month averages through November 2010 to determine the inventory quantities for stored gas and oil. For nuclear fuel inventory, Staff used an 18-month average of the value of the nuclear fuel that was contained in the fuel core of the Callaway Nuclear Generating unit through November 2010. Staff will continue to examine the actual inventory quantities for all of these items through the true up period ending February 28, 2011.

Staff Expert/Witness: Lisa K. Hanneken

E. Customer Demand-Side Management Programs Regulatory Asset

1. Demand-Side Management Cost Recovery

a. Status of Ameren Missouri's Demand-Side Management Programs

Ameren Missouri began implementing its current demand-side management (DSM) programs in February 2009 for energy efficiency programs contained in the Company's adopted preferred resource plan which was filed on February 5, 2008 in Case No. EO-2007-0409. Ameren Missouri is currently offering its customers five residential energy efficiency programs and four business energy efficiency programs. All nine of Ameren Missouri's DSM programs are effective through September 30, 2011 and will terminate thereafter unless modified or extended. Ameren Missouri has one voluntary demand response program (Rider L Peak Power Rebate) which has an effective date of July 9, 2009 and which was utilized during the summer of 2009 but was not utilized during the summer of 2010. Rider L will expire on December 31, 2011. Ameren Missouri's last adopted preferred resource plan includes seven DSM programs which Ameren Missouri has not yet implemented even though the Commission's *Final Order Regarding AmerenUE's 2008 Integrated Resource Plan* was issued on February 19, 2009.

On September 15, 2010, Staff provided to the Commission a Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives (File No. AO-2011-0035). Attached to this Staff COS Report as Appendix 3, Schedule JAR-1 are pages from the Status Report which highlight the Ameren Missouri DSM Quarterly Stakeholder Group[25] process, Ameren Missouri's implemented and planned DSM programs and the challenges and successes to date of Ameren Missouri's DSM programs. Appendix 3, Schedule JAR-2 is Ameren Missouri's Demand-Side Resources Performance Summary Report which was prepared by Ameren Missouri in response to Staff Data Request No. 381 and includes Ameren Missouri's "estimates" of actual energy and demand savings and Ameren Missouri's reported costs for its DSM programs through December 31, 2010. Following is Staff's high level summary of the Ameren Missouri's Demand-Side Resources Performance Summary Report for DSM programs through December 31, 2010:

continued on next page

[25] The Ameren Missouri DSM Quarterly Stakeholder Group includes Staff, The Office of the Public Counsel, Missouri Department of Natural Resources and other interested parties and serves as an advisory group to Ameren Missouri in the development, implementation, monitoring and evaluation of the Ameren Missouri's demand response, energy efficiency and affordability programs.

Cumulative Energy Savings (MWh)

	Program Year 1	Program Year 2	Program Year 3
Resource Plan	123,836	269,186	429,435
Actual	19,478	164,367	221,245
Variance	(104,358)	(104,819)	(208,190)

Cumulative Demand Savings (MW)

	Program Year 1	Program Year 2	Program Year 3
Resource Plan	106	131	161
Actual	11	29	37
Variance	(95)	(102)	(124)

Cumulative Cost ($000)

	Program Year 1	Program Year 2	Program Year 3
Resource Plan	$ 25,021	$ 57,144	$ 96,814
Actual	$ 10,884	$ 30,382	$ 37,761
Variance	$ (14,137)	$ (26,762)	$ (59,053)

Notes:

1. Program Year 1, Program Year 2 and Program Year 3 are 12-months ending September 30, 2009, 2010 and 2011, respectively.

2. Program Year 3 Resource Plan values are for 12 months while Program Year 3 Actual values include only three months (October - December 2010) for Program Year 3.

3. Actual values for Energy Savings and for Demand Savings are estimates provided by Ameren Missouri. These values will change once evaluation, measurement and verification of all programs' results are performed by an independent contractor.

Ameren Missouri has a total budget of $85 million for its Business Energy Efficiency tariff and its Residential Energy Efficiency tariff through September 30, 2011 (the end of Program Year 3) and has spent a total of $38 million through December 31, 2010. Assuming a spending rate of $2.5 million per month (the average monthly spending for October through December 2010 total spending level in Schedule JAR-2) for the period January through September 2011, Ameren Missouri will spend a total of $60 million through September 30, 2011 which is $25 million less than the $85 million total budget for its Business Energy Efficiency and Residential Energy Efficiency tariffs. Such "under spending" is not unusual during the early years of demand-side programs' implementation as the utility climbs the learning curve and as its customers become familiar with newly offered demand-side programs and decide to take actions necessary to participate in demand-side programs.

The energy and demand impacts and the overall delivery processes of Ameren Missouri's DSM programs are being evaluated, measured and verified by third-party contractors chosen and paid for by Ameren Missouri. Ameren Missouri anticipates that evaluation, measurement and verification (EMV) reports for all of its DSM programs will be received from its EMV contractors and will be provided to DSM Stakeholder Group members not later than April 2011.

Staff Expert/Witness: John A. Rogers

b. Residential Lighting and Appliance Program

Staff has concerns about the prudence and performance of the Company's Residential Lighting and Appliance program (L&A) (Tariff Sheet Nos. 239 – 241) and recommends that the cost of the L&A be left in the regulatory asset account and not included in Ameren Missouri's cost of service for setting rates in this case.

Staff's concerns for the L&A were first raised on May 12, 2009 in File No. ET-2009-0404 in the form of *Staff Recommendation to Approve Tariff Sheets If AmerenUE Accepts Conditions* in which Staff expressed its belief that this market transformation program was very risky primarily because: 1) the program's benefits would be very difficult to measure, and 2) national market transformation efforts for ENERGY STAR® products have been underway since 1992 and are expected to accelerate with or without the L&A.

In Ameren Missouri's last rate case (File No. ER-2010-0036) the Commission's March 24, 2010 *Order Approving First Stipulation and Agreement* approved the following agreement of the signatories to the First Non-unanimous Stipulation and Agreement:

> 10. Except to change the amortization period from 10 years to 6 years, AmerenUE's existing DSM regulatory asset shall continue, with the unamortized balance to be included in AmerenUE's rate base for the actual expenditures booked to the DSM regulatory asset through December 31, 2009, less the expenditures for the "Residential Lighting and Appliance Program" (which are agreed to have been $3,673,624 through December 31, 2009). The amount of the unamortized balance in AmerenUE's DSM regulatory asset to be included in AmerenUE's rate base upon which rates will be set in this case is $11,430,501. The signatories agree to continue to work collaboratively regarding AmerenUE's recovery of its DSM expenditures.

At this time Staff does not have the information that it needs to determine whether or not the costs for the L&A were prudently spent. Staff recommends that the L&A expenses remain in the DSM regulatory asset, pending Staff's review of the EMV report for the L&A. Should Staff receive the EMV report for the L&A in April 2011 as expected, Staff will review the report and, depending on the results and the evaluation techniques used by the EMV contractor, may recommend that some or all of the L&A costs be included in the test year true up revenue requirement for this case.

Staff Expert/Witness: John A. Rogers

c. DSM Cost Recovery

Ameren Missouri witness William R. Davis provides direct testimony in which he requests: 1) continuation of the DSM regulatory asset and rate base treatment of DSM related expenditures with a reduction of the amortization period from six years to three years, and 2) approval of a fixed cost recovery mechanism (FCRM). Mr. Davis' proposed FCRM will have no impact on the revenue requirement in this case and would not include any interim rate adjustments prior to Ameren Missouri's next general rate case. Mr. Davis states that the purpose of his proposed cost recovery mechanism and FCRM is to "move toward implementation of the state policy of aligning Ameren [Missouri's] financial incentives to help customers use energy more efficiently." Staff appreciates the testimony of Mr. Davis and Ameren Missouri's initiative to request an alternative cost mechanism prior to the Commission's Missouri Energy Efficiency Investment Act of 2009 (MEEIA) rule go into effect. However, Staff recommends that the Commission not approve Mr. Davis' request for a change to Ameren Missouri's current DSM cost recovery mechanism and not approve the proposed FCRM in this case. As an alternative, Staff encourages a more comprehensive approach to filing an application for approval of its DSM programs and to filing an application for approval of a demand-side programs investment mechanism (DSIM) under the soon-to-be-approved MEEIA rules. This comprehensive approach takes into account the soon to be effective MEEIA rules and Ameren Missouri's next Chapter 22 Electric Utility Resource Planning compliance filing which Ameren Missouri is scheduled to file on February 23, just nineteen days after the filing of this report. This Chapter 22 compliance filing should include DSM programs designed using the results of Ameren Missouri's service territory potential study.

Staff Expert/Witness: John A. Rogers

d. Missouri Energy Efficiency Investment Act of 2009

The MEEIA was established in Senate Bill 376 and became law on August 28, 2009. During 2009 and 2010, Staff organized a stakeholder process including a series of workshops to obtain stakeholder input and to promulgate rules in compliance with MEEIA (File No. EW-2010-0265). Staff subsequently filed proposed MEEIA rules with the Commission in File No. EX-2010-0368. On October 4, 2010, the Commission sent the proposed MEEIA rules to the Office of the Secretary of State. The proposed MEEIA rules were published in the *Missouri Register* on November 15, 2010. The Commission held a hearing regarding the proposed MEEIA rules for December 20, 2010 and will send its proposed MEEIA rules to the Missouri Joint Committee on Administrative Rules by February 10, 2011.

Staff has evaluated the typical timeline for rulemakings established in Chapter 536, RSMo, and concludes that a final order of rulemaking for the MEEIA rules can be reasonably expected so that MEEIA rules will first be effective June 2011.

Staff Expert/Witness: John A. Rogers

e. Ameren Missouri's Next Chapter 22 Filing

Ameren Missouri's next Chapter 22 compliance filing is due on February 23, 2011 (File No. EE-2010-0243). It is expected that Ameren Missouri's Chapter 22 compliance filing will include a fresh and more aggressive approach to demand-side resources as a result of information contained in Ameren Missouri Demand-Side Management Market Potential Study (Potential Study) performed by Global Energy Partners and published in January 2010. A copy of Volume 1 Executive Summary of the Potential Study is included as Appendix 3, Schedule JAR-3. The following charts illustrate the significant increase in energy savings potential and demand savings potential for realistic achievable potential (RAP) and maximum achievable potential (MAP) contained in the Potential Study compared to the business as usual (BAU) case included in Ameren Missouri's 2008 adopted preferred resource plan.

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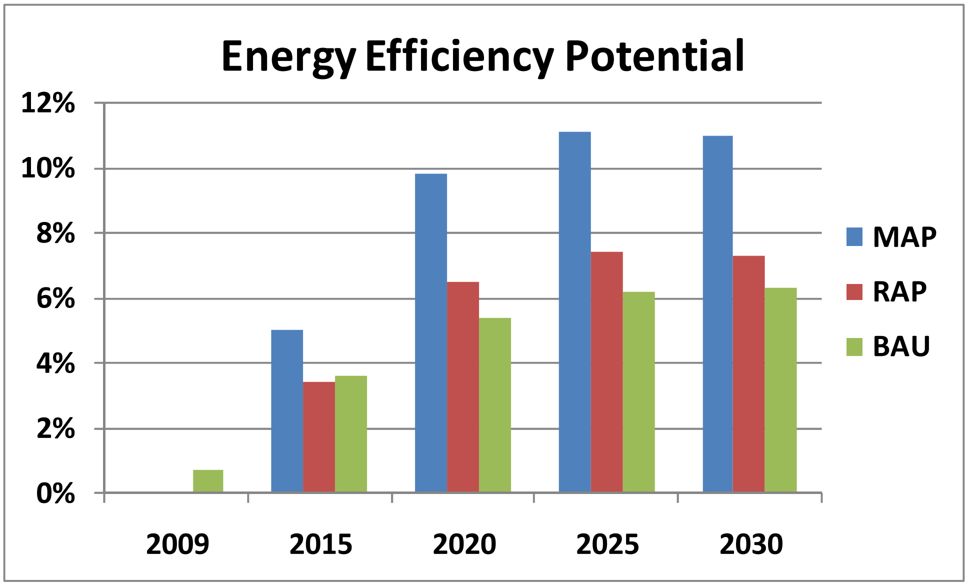

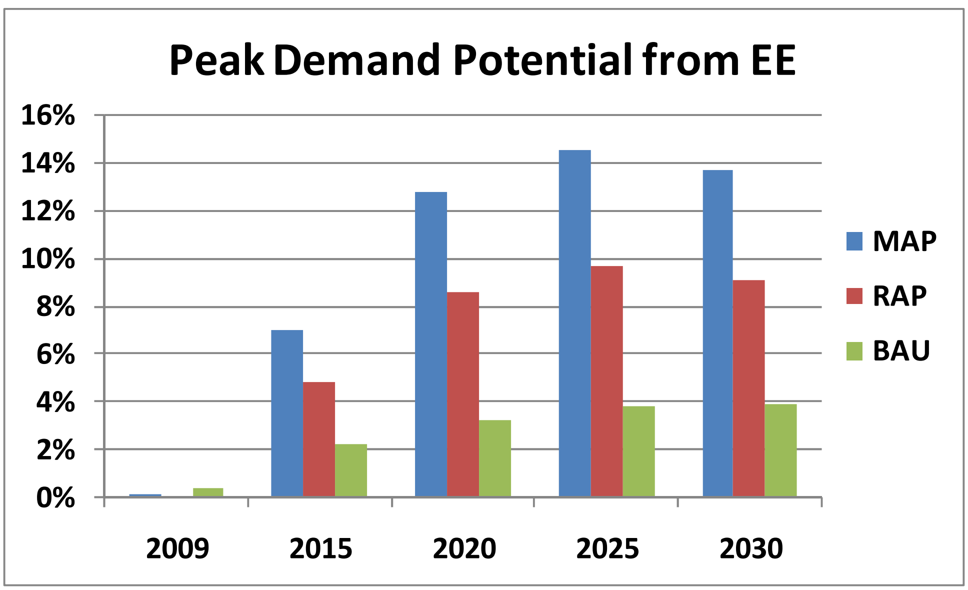

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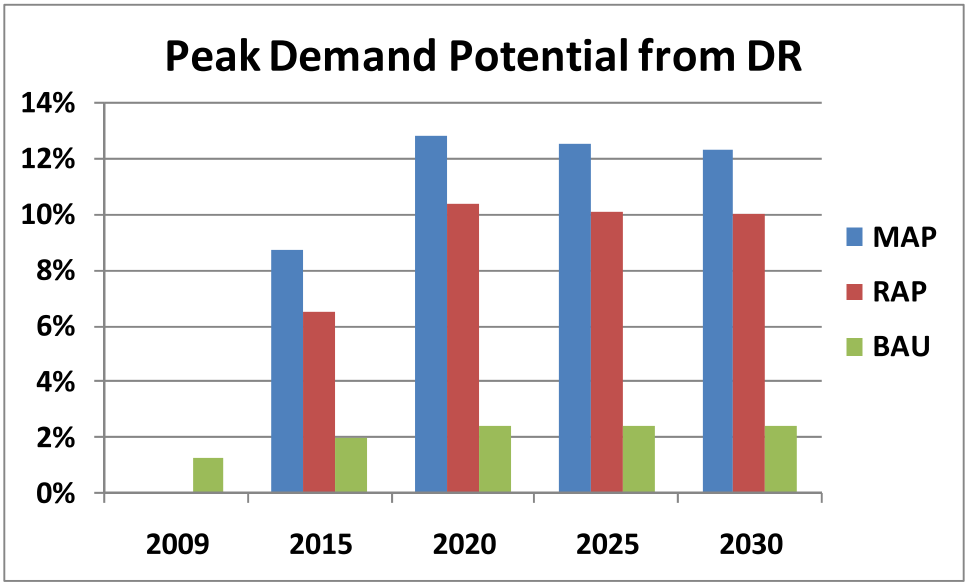

Staff would like to highlight the following from page ES-2 of Appendix 3, Schedule JAR-3: "Concurrent with higher [energy and demand savings] opportunities, budgets to harvest those opportunities reach an annual spend range of $100 million [for RAP] to $200 million [for MAP] by 2015."

Staff Expert/Witness: John A. Rogers

f. Summary of Significant Scheduling Opportunity for Ameren Missouri in 2011

Staff would like to point out the significant scheduling opportunity that Ameren Missouri has in 2011 related to approval of DSM programs and approval of DSIM under the soon-to-be-effective MEEIA rules. The Company will file on February 23, 2011 its Chapter 22 compliance filing, and Staff, The Office of the Public Counsel and interveners are expected to submit their reports by June 23, 2011. It is also expected that MEEIA rules will be effective in June 2011. If MEEIA rules are effect in June 2011, and if Ameren Missouri files its applications for approval of DSM programs and for approval of a DSIM by the end of June 2011, Ameren Missouri could have approved DSM programs and an approved DSIM under MEEIA rules by the end of October 2011. Staff also notes that Ameren Missouri's current DSM programs' tariffs all expire on September 30, 2011 unless extended.

The following chart summarizes the above discussion and illustrates the significant scheduling opportunity for Ameren Missouri in 2011.

Optimum Schedule for Ameren Missouri's Approval of DSM Programs and DSIM Under MEEIA Rules

	2010				2011											
	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
ER-2011-0028 Rate Case	Filed 9/3/10						Operation of law date 8/3/11									
4 CSR 240-22 IRP Case						File 2/23/11		Reports 6/23/11								
MEEIA Rules										June effective date expected						
4 CSR 240-20.093 Case											File DSIM			Order		
4 CSR 240-20.094 Case											File Programs			Order		
Current DSM Tariffs							Term for all current DSM tariffs is 9/30/11									

Staff Expert/Witness: John A. Rogers

g. Staff Recommendation

Staff recommends that the Commission not change the current Ameren Missouri DSM cost recovery mechanism and not approve a fixed cost recovery mechanism for Ameren Missouri in this case. Staff recommends that Ameren Missouri instead focus its attention on working with its stakeholders during the upcoming Chapter 22 compliance filing review to reach alignment on the strategy for the Company's demand-side resources. Such alignment in the Chapter 22 compliance case is possible by June 2011, the same month in which the MEEIA rules are expected to become effective. As discussed earlier in this section of Staff's COS Report, Ameren Missouri could have approved DSM programs and an approved DSIM under the MEEIA rules by the end of October 2011.

Further, at this time Staff does not have the information that it needs to determine whether or not the costs for the L&A were prudently spent. Staff recommends that the L&A expenses remain in the DSM regulatory asset, pending Staff's review of the EMV report for the L&A. Should Staff receive the EMV report for the L&A in April 2011 as expected, Staff will review the report and, depending on the results and the evaluation techniques used by the EMV contractor, may recommend that some or all of the L&A costs be included in the test year true up revenue requirement for this case.

Staff Expert/Witness: John A. Rogers

2. Low-Income Weatherization

There are specific programs designed to help low-income customers with energy conservation. Low-income consumers often live in housing that is energy inefficient with substandard insulation and other deficiencies. These customers would benefit from building shell energy conservation measures such as weatherization or more energy-efficient appliances. The Low Income Weatherization Assistance Program (Weatherization Program) is administered by the Missouri Department of Natural Resources (MDNR) using federal, state, and utility funding. The Weatherization Program is administered locally by Community Action Agencies or other local agencies (Weatherization Agencies). In the Ameren Missouri service area the Weatherization Program is administered by the twelve Weatherization Agencies listed on Appendix 3, Schedule HEW 1.

The federal government, through the American Recovery and Reinvestment Act (ARRA), is providing special funding of $128 million for the Missouri Weatherization Program for the period of April 2009 – March 2012 (ARRA Period). The ARRA provides an average of $6,500 of weatherization for households with income at 200% or less of the Federal Policy Guidelines. In the previous three year period (2006-2008), prior to the ARRA Period, federal funding for the Missouri Weatherization Program was approximately $18 million and the average amount of weatherization per household was $3,000. The Weatherization Agencies are making a concerted effort to utilize the ARRA funding before the March 2012 deadline.

Funding for the Ameren Missouri Weatherization Program was authorized in the Commission Order in File No. ER-2010-0036. In the Order of that case, Ameren Missouri was authorized to collect one million two hundred thousand dollars ($1.2 million) in rates annually for the low-income weatherization program. For the most recently concluded Program Year 2009-2010, the projected budget has been modified for the period as shown in Appendix 3, Schedule HEW 1. This is due to a carryover of funds from the previous year and a late installment of funds from the Company from the previous year. The actual expenditure over the period is also shown in Schedule HEW 1 of Appendix 3. In the November 2010 -- October 2011 program year, the basic funding of $1.2 million with some additional carryover is budgeted to be sent to the Weatherization Agencies for the weatherization of qualifying customers.

Some under-utilization of utility funds is because of the Weatherization Agencies' focus on using the ARRA funding and some restrictions on ARRA funds being combined with utility funds. At the end of the ARRA period, the Weatherization Agencies anticipate using any surplus utility funds to help provide for a higher level of weatherization activity than before ARRA.

The Missouri State Environmental Improvement and Energy Resources Authority (EIERA) was established to manage and disburse federal and other weatherization funds for MDNR to the Weatherization Agencies according to MDNR guidelines. Currently, Ameren Missouri and other Missouri jurisdictional utilities utilize the EIERA to manage their weatherization funds. The funds at the EIERA are invested to earn a return until they are distributed so the value of the funds is enhanced.

Staff recommends that the unutilized low-income weatherization funds from 2009-2010 remain in the EIERA account. In addition, in order have some additional Ameren Missouri funds for weatherization when the ARRA funds are no longer available, Staff recommends that Ameren Missouri continue to collect in rates and provide annual funding of $1.2 million for low-income weatherization, as currently allocated between the Weatherization Agencies with oversight by the Ameren Missouri energy efficiency stakeholder group.

Staff Expert/Witness: Henry E. Warren

3. Costs Included In The Calculation Of Revenue Requirement

The DSM regulatory asset account allows Ameren Missouri to treat the DSM programs' expenditures as a depreciable asset. In Case No. ER-2008-0318, one tenth of the amount Ameren Missouri spent through September 30, 2008 was included in the cost of service through a 10-year amortization. In File No. ER-2010-0036, as a result of the First Nonunanimous Stipulation and Agreement, $11,430,501, the balance in the regulatory asset as of December 31, 2009, less the Residential Lighting and Appliance program costs, was included in rate base and an annual amortization based on six years was included in expense. In this case, Staff has estimated the balance in the DSM regulatory asset account as of 2/28/2011. From this balance, based on the recommendation of Staff witness John A. Rogers, Staff has excluded the estimated amount of the Residential Lighting and Appliance program. This net balance, based on Mr. Rogers' recommendation, is being amortized over six years. The estimated unamortized balance of the DSM regulatory asset account, net of the estimated Residential Lighting and Appliance program amount, has been included in rate base. The Staff will re-examine

Ameren Missouri's DSM costs, including any adjustments, as part of its true-up through February 28, 2011.

Staff Expert/Witness: Stephen M. Rackers

F. FAS 87 – Pensions and FAS 106 OPEBs Trackers

See the discussion in Section VIII. E. 5 and 6 of Payroll and Benefits.

Staff Expert/Witness: Kofi Agyenim Boateng

G. Customer Deposits

The amount of this item in Accounting Schedule 2, Rate Base, represents a 13-month average (March 2009 – March 2010) of Ameren Missouri's customer deposits. Customer deposits represent funds received from the utility company's customers as security against potential loss arising from failure to pay for utility service. Until refunded, customer deposits represent a source of funds available to the company, and are included as an offset to the rate base investment. Generally, interest is calculated on customer deposits and paid to customers for the use of their money. In Accounting Schedule 10, the Staff adjusted expenses to include interest calculated on Staff's level of customer deposits reflected in rate base.

Staff Expert/Witness: Lisa M. Ferguson

H. Customer Advances

Customer advances are funds provided by individual customers of the company to assist in the costs of the provision of electric service to them. These funds represent interest-free money to the company. Therefore, it is appropriate to include these funds as an offset to rate base. No interest is paid to customers for the use of their money, unlike customer deposits. The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents a 13-month average (March 2009 – March 2010).

Staff Expert/Witness: Lisa M. Ferguson

I. Accumulated Deferred Income Taxes

Ameren Missouri's deferred tax reserve represents, in effect, a prepayment of income taxes by Ameren Missouri's customers to the Company prior to payment being made by the Company to taxing authorities. As an example, because Ameren Missouri is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, the depreciation expense deduction used for income taxes paid by the Company is considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to the Company. Therefore, Ameren Missouri's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. As part of its true-up audit, the Staff will re-examine ADIT balances to make sure all items included in those balances are consistent with the other components of the cost of service and that they reflect the current balances at the true-up cutoff date, February 28, 2011. Based on this true-up examination the Staff may make additional adjustments to the cost of service as necessary.

Staff Expert/Witness: John P. Cassidy

VII. Allocations

A. Jurisdictional Allocations Factors

1. Overview

In determining the cost of service in the current case, the Staff has used the traditional method of allocating costs to the retail jurisdiction when there is also a wholesale jurisdiction. For Ameren Missouri, the wholesale jurisdiction is comprised of five municipalities that buy power from Ameren Missouri through a separate contract to resell to their citizens. The traditional method for determining the costs allocated to the retail jurisdiction to determine the retail cost of service is accomplished by applying a retail jurisdictional allocation factor to the utility's (in this case Ameren Missouri's) total amount of investments and expenses. The retail cost of service is then compared to the retail revenues generated by the current effective retail rates to determine the additional revenue and incremental rate increase for retail customers. Thus, the retail jurisdiction and the wholesale jurisdiction are allocated both rate base and expense costs. Any wholesale revenue the utility receives from municipalities is excluded in the determination of the utility's retail revenues. Here, Staff excluded Ameren Missouri's revenues from its five municipal customers from Ameren Missouri's retail revenues.

In this rate case, unlike Staff, Ameren Missouri did not completely exclude revenues from its five municipal customers in its direct filing. In addition, Ameren Missouri did not exclude its costs to serve those wholesale customers from its cost of service upon which it proposes its retail customers' rates be set,

Stated another way, when Ameren Missouri determined its retail revenues, it did not recognize either the existence of the municipal customers' contracts or the municipal customers' generation requirements on Ameren Missouri's system. Instead, Ameren Missouri has imputed off-system sales it could make from the generation it is using to serve its wholesale municipal customers. Ameren Missouri has included these revenues from imputed off-system sales in determining its retail revenue requirement, which acts to offset the additional cost of service caused by not excluding its costs to serve those wholesale customers and by allocating to cost of service only its costs to serve the retail jurisdiction.

Staff is not opposed to moving away from the traditional jurisdictional allocation method of determining the retail cost of service. However, Staff believes that such a change in approach should reflect the actual requirements to serve municipal load and all the revenues that would be generated from these sales that result from existing contractual obligations.

Staff Expert/Witness: Stephen M. Rackers

2. Determination of Jurisdictional Allocation Factors

Jurisdictional allocation factors are used to allocate demand-related and energy-related costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriately allocated on the basis of energy consumption. In this case, demand-related and energy-related costs are divided among two jurisdictions: retail and wholesale. The particular allocation factor applied is dependent upon the type of cost that is being allocated.

Demand Allocation Factor - Demand refers to the rate at which electric energy is delivered to a system to match the requirements of its customers ("load"), generally expressed in kilowatts (kWs) or megawatts (MWs), either at an instant in time or averaged over a specified time interval. System peak demand is the largest electric requirement ("load") that occurs within a specified period of time, (e.g. hour, day, month, season and year) on a utility's system. Since generation units and transmission lines are planned, designed, and constructed, to meet a utility's anticipated system peak demands, plus required reserves, the contribution of each of the Ameren Missouri's two jurisdictions, wholesale and retail, coincident to the system peak demand, i.e., each jurisdiction's demand at the time of the system peak, is the appropriate basis on which to allocate these facilities. Thus, the term coincident peak (CP) refers to the load, generally in kWs or MWs, in each of the jurisdictions that coincides with Ameren Missouri's overall system peak recorded for the time period in the corresponding analysis.

Staff is utilizing a Twelve Coincident Peak (12 CP) methodology to determine demand allocation factors for Ameren Missouri. Although it is not sponsoring jurisdictional allocation factors in the present case, Ameren Missouri utilized a 12 CP methodology in its recommendation of jurisdictional demand allocation factors in both of its most recent rate cases, Nos. ER-2008-0318 and ER-2010-0036.

Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify Ameren Missouri's peak hourly load in each month for the time period August 2009 through July 2010 and sum the hourly peak loads.

b. Sum the particular jurisdiction's corresponding loads for the hours indentified in a. above.

c. Divide b. by a. above.

The result is the allocation factor for each jurisdiction:

Retail:	0.9907
Wholesale:	0.0093

Energy Allocation Factor - Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor, for each individual jurisdiction, is the ratio of the normalized annual kilowatt-hour (kWh) usage of each particular jurisdiction to the total normalized Ameren Missouri kWh usage. The kWh usage data includes adjustments for losses, anticipated growth, annualizations and non-normal weather. Staff witnesses Kofi Agyenim Boateng and Curt Wells, respectively, provided the growth and annualization adjustments. Staff witnesses Shawn E. Lange and Walt Cecil provided the weather adjustments. Staff has calculated the following jurisdictional energy allocation factors utilizing the twelve-month period ending July 2010:

Retail:	0.9917
Wholesale:	0.0083

Staff witness Stephen M. Rackers used these demand and energy jurisdictional allocation factors in determining Staff's cost of service for Ameren Missouri in this case.

Staff Expert/Witness: Alan J. Bax

B. Corporate Allocations

A subsidiary of Ameren Corporation, Ameren Services Company (AMS), provides various management and administrative services for Ameren Missouri. In its audit, Staff reviewed the methods used by AMS to assign and allocate its costs to Ameren Missouri's electric operations. Under AMS's corporate cost allocation system, costs are categorized into four types: Direct, Direct Allocated, Indirect Corporate, and Indirect Function. The allocations of costs and the methods used to allocate costs from AMS are provided in Ameren Missouri's cost allocation manual (CAM).

AMS evaluates and updates the allocation factors at the beginning of each calendar year, unless a significant change in circumstances occurs which would require an intermediate factor update. In addition, the Company's internal auditing department performs an audit each year of the Service Request System and Service Request policies, operating procedures, and controls as ordered by the Illinois Commerce Commission (ICC) in Order #06-0070 on May 16, 2007.

The Company provided Staff with data regarding its allocations through November 2010 for review, as well as copies of the internal audit reports required by the ICC. While Staff is not recommending an adjustment at this time, Staff will need to examine the allocation of AMS costs to Ameren Missouri's electric operations through the true-up period ending February 28, 2011 to determine if any significant changes have or will take place subsequent to the November 2010 data provided.

Staff Expert/Witness: Lisa K.Hanneken

VIII. Income Statement

A. Rate Revenues

1. Introduction

Since the largest component of operating revenues result from rates charged Ameren Missouri's retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates Ameren Missouri charges its Missouri retail customers for electricity is required.

One of the major tasks in a rate case is to not merely determine whether a deficiency (or excess) between cost of service and operating revenues exists, but to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues) prospectively.

Staff Expert/Witness: Kofi Agyenim Boateng

2. Definitions

Operating Revenues are composed of Rate Revenue, Revenue from Off-System Sales, and Other Operating Revenue.

Rate Revenue: Test year rate revenues consist solely of the revenues derived from Ameren Missouri's charges for providing electric service to its Missouri retail customers (native load and customer charges). Ameren Missouri's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. In Missouri, different rates apply to different times of the year (summer vs. winter); different types of charges (demand vs. energy); and to customers in different rate classes (differentiation by type and amount of use). Revenues from the fuel adjustment clause (FAC) represent collections or refunds of prior period fuel cost and are not included in determining the ongoing annual level.

Revenue from Off-System Sales: Revenue from off-system sales is realized as a result of Ameren Missouri selling electricity to other utilities at non-regulated prices. The gross revenues from theses sales, less the generation or purchased power expense Ameren Missouri incurs in order to make the sales, is the profit margin on off-system sales. The rationale for assigning the profit to ratepayers is that the electricity sold is generated by power plants being paid for by ratepayers.

Other Operating Revenue: This category includes the revenue from such items as the rental of pole space, leased land and other miscellaneous charges.

Staff Expert/Witness: Kofi Agyenim Boateng

3. The Development of Rate Revenue in this Case

The objective of this section is to describe Staff's process to determine annualized, normalized test year usage and revenues by rate class. Staff makes adjustments to test year Missouri usage and rate revenues to determine the level of revenue that the Company would have collected on an annual, normal-weather basis, based on information "known and measurable" at the end of the test year (in this case, updated through July 31, 2010 as explained below).

The two major categories of revenue adjustments are known as "normalizations" and "annualizations." Normalizations deal with test year events that are unusual and unlikely to be repeated in the years the new rates from this case are in effect. Test year weather is an example. Annualizations are adjustments that re-state test year results as if conditions known at the end of the test year had existed throughout the entire test year.

Staff Expert/Witness: Curt Wells

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Adjustment to Remove Unbilled Revenues

Staff has eliminated unbilled revenue from its determination of revenue requirement. The recording of unbilled revenue on the books of the Company is an attempt to recognize sales of electricity that have occurred, but have not been billed to the customer. Since the Staff has adjusted revenues to assure that it includes only 365 days of revenue, and since the revenues have been restated to a billed basis, it is necessary to remove unbilled revenue in order to reach an accurate revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

b. Adjustment to Remove Gross Receipts Tax

The Company acts as a collector for taxes imposed on utility service revenues by municipalities and other taxing jurisdictions. The Gross Receipts Tax (GRT) included on a customer's bill is collected by the Company and remitted to the appropriate taxing jurisdiction. The GRT included on a customer's bill is recorded as revenue on the books of the Company, with a corresponding charge booked to GRT expense. Theoretically, the revenue and expense offset one another and, therefore, have no effect on net income. However, the expense accrual for GRT does not always match perfectly with the GRT included in revenue due to timing differences in the collection and payment of GRT. Eliminating the GRT recorded in revenue and expense through companion adjustments assures that GRT will have no impact on the calculation of net income or revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

c. Preliminary Adjustments to Test Year

Starting with revenue based on Revenue Month (the month in which usage and revenue were reported in the Company billing system), Staff adjusted Ameren Missouri's revenue in all rate classes to reclassify revenues to Primary/Rate Month (the month reflecting the rates and revenue in the month when service actually occurred).

Staff Expert/Witnesses: Curt Wells and Seoun Joun Won

d. Update Period Adjustment

Staff's analysis of Ameren Missouri data provided by Staff witness Walt Cecil showed that Net System Input and usage for 2010 differ significantly from the corresponding months of 2009, possibly affected by recent economic conditions. To provide a more current basis for normalization, annualization, and growth calculations, usage data used to determine revenue in this case were updated to reflect the 12 month period ending July 2010 and also to include minor billing adjustments.

Staff Expert/Witnesses: Curt Wells and Seoun Joun Won

e. Large Customer Annualization

i. Large Primary Service (LPS) Rate Class

The adjustments were based upon an updated test year of August 1, 2009, through July 31, 2010, to be adjusted for known and measurable changes through the true-up period February 28, 2011. There were 76 customers in the LPS rate class during the updated test year. A data check was done for billing corrections prior to doing adjustments. LPS customers were annualized on an individual customer (account) basis. Their individual monthly demand and energy use, measured over multiple years prior to the test year and the 12 months of the updated test year were examined graphically to determine if an adjustment was needed, and the type of adjustment needed.

Ameren Missouri's Economic Development Rider (EDR) provides for discounts to be "paid" to customers (in the form of credits on their electricity bill) who locate or expand operations in Ameren Missouri's service territory. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. The discount is 15% over the contract period. Staff assumed that the annualization for the rate change would be reflected in both the level of the bill before the credit and in the amount of the credit itself (i.e., a 10% rate change would increase both the pre-credit bill and the EDR credit by 10%). These discounts are included in the determination of Ameren Missouri's revenues because fostering economic development is assumed to be a benefit to all ratepayers.

The other LPS adjustments are as follows:

(a) Annualization for Rate Switching

During the updated test year three (3) customers switched from the Small Primary Service (SPS) rate class to the Large Primary Service (LPS) rate class, and four (4) customers switched from the LPS class to the SPS class. For those switching into the LPS class, an adjustment was made by moving those customers' test year usage data for the affected months from the SPS class to the LPS class and applying LPS rates to that usage. Test year usage of customers leaving the LPS was removed from LPS, with their usage in SPS accounted for in customer growth in that class.

(b) Annualization

The general intent of an annualization is to re-state test year kWh results as if conditions known at the end of the update test year period had existed throughout the entire test year. Staff typically annualizes each of the very largest customers individually to reflect any major growth or decline in kWh usage and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers.

As part of load annualization, four LPS customers were load adjusted. The load that seemed incongruous or was expected to change in their future consumption was replaced by average numbers from adjacent months or by other year monthly data when their load seems to be more representative of their future consumption. In addition, the load of three new LPS customers was annualized to include usage for all 12 months.

(c) 365-Days Adjustment

Rate revenues and kWh usage were measured by billing month (the period of time over which the staggered bill cycles result in each customer being billed precisely once) rather than by calendar month. The number of days in the 12 billing months comprising the test year for each customer was compared to a 365 day calendar year. For those LPS customers with greater or less than 365 days, a per-day kWh adjustment was made, with the appropriate rates applied to determine the revenue adjustment. Days adjustments are also known as "unbilled" sales and "unbilled" revenues on financial statements.

ii. Large Transmission Service (LTS) Rate Class

There was only one customer in the LTS rate class during the test year. That customer's electric consumption from August 2009 to February 2010. during the updated test year, was significantly reduced due to an ice storm that hit its facility in January 2009. Staff has annualized the load for that account by considering its future expected consumption. For the adjusted test year, Staff supplemented 2010 "full capacity" monthly usage with 2008 monthly usage and where necessary, averages based on these "full capacity" months.

Staff Expert/Witness for LPS and LTS classes: Seoung Joun Won
Staff Expert/Witness for all other classes: Curt Wells

f. Annualization for Rate Change

Test year rate revenues do not reflect any of the changes to Ameren Missouri's rates made on June 21, 2010, as a result of Case No. ER-2010-0036. Thus, test year revenues are understated by the difference between the amount that was actually billed to customers during the test year as updated and the amount that would have been billed to customers by the Company if the current rates (effective June 21, 2010) had been in effect throughout the entire period. The Staff's method of computing annualized revenues for each rate class is to multiply updated test year billing units by current rates. The difference between these computed annualized revenues and the amounts billed during this period under the prior rates provide the amount of the adjustment.

Staff Expert/Witness for LPS and LTS classes: Seoung Joun Won
Staff Expert/Witness for all other classes: Curt Wells

g. Weather Normal Variables

The actual weather experienced during the test year is unique and unlikely to be repeated exactly in each of the years when the new rates from this case are in effect. Since each year's weather is unique, test-year usage need to be adjusted to "normal" weather. In this case, Staff's adjustments to usage and revenue are based on an updated test year period (August 1, 2009 through July 31, 2010).

NOAA[26] states that "A climate normal is defined, by convention, as the arithmetic mean of a Climatological element computed over three consecutive decades." The Climatological elements being computed in this case are observed daily temperatures. To conform to the NOAA's three consecutive decades the time period used in the case, in determining the normal values of temperature, is the 30-year period of January 1, 1971 through December 31, 2000. However, the NOAA normal temperatures cannot be directly used due to inconsistencies and biases that have resulted from weather instruments being moved (either horizontally, vertically, or both), replaced or updated, and changes in observation procedures. To account for such inconsistencies and biases, certain adjustments have been made to the actual daily temperatures based on the adjusted daily temperature data from the Midwestern Regional

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[26] National Oceanic and Atmospheric Administration

Climate Center's (MRCC) database for St. Louis Lambert International Airport weather station. The adjustments made to the actual daily temperatures were agreed upon by Company and Staff in Case No. EM-96-149.

The data required to weather normalize usage is the actual and normal two-day weighted mean daily temperatures. To calculate the two-day weighted mean temperature, the current day's mean temperature is averaged with the prior day's mean temperature applying a 2/3 weight on the current day and 1/3 weight on the prior day. This is done in order to bring forward the previous day's residual effect on the current day's usage.

Normal weather ranking - For this case, Staff followed the methodology used by both the Company and the Staff in the Company's most recent rate case (File No. ER-2010-0036). Staff uses normal weather temperature to normalize both class usage and hourly net system loads. This ranking method estimates daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating normal extremes. The daily temperature normals are calculated by averaging the ranked temperatures in each year of the 30-year normals period, irrespective of the calendar date. This results in the normal extreme being the average of the most extreme temperatures in each year of the normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

Because actual temperatures do not smoothly move up and down during the year,[27] these normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the updated test year.

This information was provided to Staff witness Walter Cecil for weather normalization.

Staff Expert/Witness: Seoung Joun Won

h. Weather Normalization of Usage

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature reaches higher levels, the demand for cooling, air conditioning and fans, increases the consumption of electricity. As the weather becomes cold and temperature falls, the demand for additional heating, electric space heating for

[27] For example, In July a Monday and Tuesday may be hot days but it cools down on Wednesday. However, it is still likely that on the weekend it will be hot again.

example, also forces an increase in electricity consumption. Electric air conditioning and space heating is prevalent in Ameren Missouri's service territory; therefore, it follows Ameren Missouri's electric load is linked and responsive to temperature.

Ameren Missouri's test year ran from April 1, 2009 through the end of March 2010. As Staff analyzed Ameren Missouri's daily load data through July 2010 it was found non-residential usage per customer is generally equal to or less than 2009 levels and in all cases is below 2008 levels. In Staff's estimation that part of electricity consumption which is not related to climate control (heating and cooling) was changing perhaps due to the recent changes in economic activity. In an attempt to capture a more likely forward-looking indictor of non-weather electricity usage per customer, Staff determined to use the most recent temperature-load data available at the time and, therefore, based its analysis on the period August 1, 2009 through July 31, 2010.

August 2009 experienced temperatures cooler than normal resulting in electric energy usage below that which would have been expected under normal weather conditions. September and October 2009 experienced temperatures warmer than normal resulting in usage above that which would have been anticipated under normal conditions. The months of January and February 2010 saw temperatures cooler than normal which resulted higher usage of electric energy than would have been anticipated under normal weather conditions. The months of March through July 2010 were warmer than normal and experienced electrical usage exceeding that which would have been expected under normal conditions. Since the temperatures in the test year used by Staff deviated from normal and since Staff chose a more recent test year to review than the one used by Ameren Missouri, Staff performed its own weather impact analysis. However, the method and model used by Staff is similar to those used by Ameren Missouri.

Staff's model and methodology contained elements important in the class level weather normalization process: use of daily load research data to determine non-linear class specific responses to changes in temperature with the incorporation of different base usage parameters to account for different days of the week, months of the year and holidays. The results of Staff's analysis were provided to Staff witness Curt Wells to be used in the normalization of revenues for the Residential (Res), Small General Service (SGS), Large General Service (LGS) and Small Primary service (SPS) classes.

Staff did not weather normalize the Large Primary Services (LPS) class. The members of this class are not homogeneous and, consequently, a weather response function created for one member should not be applied to any other member. Staff believes it is both appropriate and necessary to annualize rather than normalize LPS for changes in customer usage and count. Please see *Large Power Annualization* by Staff witness Seoung Joun Won for a more detailed explanation of the annualization adjustments for the LPS class. Applying the weather normalization process to annualized usage would have introduced statistical error into the product of the analysis.

Weather normalization of usage results for the Res, SGS, LGS and SPS classes were provided to Staff witness Curt Wells.

Staff Expert/Witness: Walt Cecil

i. Weather Normalization of Usage and Revenue

Test year usage data provided by Ameren Missouri as updated for the Res, SGS, LGS, and SPS rate classes were normalized for weather by applying weather normalization factors provided by Staff witness Walter Cecil for each class for each month. The billing units were adjusted by these factors and current rates were applied to determine weather normalized revenue. The difference between these weather-normalized revenues and the test year revenues, as adjusted above, determined the amount of the adjustment.

Staff Expert/Witness: Curt Wells

j. 365-Days Adjustment For Weather Sensitive Classes

Staff calculated a normalization adjustment to Ameren Missouri's kWh usage to reflect a calendar year's (365 days) worth of usage. Ameren Missouri's customers' usage is measured and rate revenue are collected over a period known as a revenue month which is the interval that Ameren Missouri reads customers' meters and issues bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months but revenue months take their names from the calendar month in which the customer's bill is rendered. For example, assume a customer's meter was read and usage determined on June 8 and then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for this bill is July even though most of the usage measured for this bill occurred in June.

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than or less than the number of days for the same-named calendar month. For the example given above, the usage is for 30 days (June 8 through July 8) even though the revenue month is July which has 31 days. When revenue month usage is totaled over the year, the resulting revenue year will include usage from the immediately prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain more than or less than 365 days' usage. Therefore, since the costs and expenses are accounted over a calendar year, Staff calculates a normalization adjustment to bring the revenue year kWh into a 365-days interval. This adjustment is stated in kWh is referred to as a *days adjustment.*[28]

Staff calculates the days adjustment by subtracting the weather normalized revenue month kWh from the weather normalized calendar month kWh for the test year; the difference, or the days adjustment, may be either positive or negative.

The days adjustment for the weather sensitive classes were provided to Staff witness Curt Wells who used the days adjustment to adjust the revenues of the weather normalized class revenues months to the 2009 calendar year. The annual total days adjustment for the weather sensitive classes in this case is 203,144,690 kWh.

Staff Expert/Witness: Walt Cecil

k Annualization and Normalization Results

Results of the annualization and normalization adjustments above are located at the Rate Revenue Summary tab of the Staff Accounting schedules.

Staff Expert/Witness: Curt Wells

l. Customer Growth Annualization

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additions to, and in certain cases, reduction to kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of July 31, 2010, had existed

[28] Days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

throughout the entire test year. Customer growth was calculated for the Res Non-Time-of-Use, SGS Non-Time-of-Use, LGS Non-Time-of-Use, and SPS Non-Time-of-Use and SPS Time-of-Use customer classes. The customer growth annualization takes into account weather and usage normalizations, as well as the adjustments for 365 days and rate changes that occurred during the test year. Other customer classes that did not exhibit growth were left at test year customer levels instead of being annualized to end of July 31, 2010. These classes include Res Time-of-Use, SGS Time-of-Use, SGS Unmetered, LGS Time-of-Use, LPS, Outdoor Lighting, and LTS. The Staff will re-examine the level of Customer growth through February 28, 2011 during its true-up audit.

Staff Expert/Witness: Kofi Agyenim Boateng

m. Results

The results of modified year adjustments to the classes' retail rate revenue can be found in the RateRevSummary tab of the Staff Accounting Schedules (EMS).

Staff Expert/Witness: Kofi Agyenim Boateng

n. Removal of Rate Refunds

Staff made an adjustment to remove the provision for rate refunds recorded by the Ameren Missouri during the test year. This item relates to the collections or refunds of prior period revenues of the Company’s FAC and is, therefore, appropriately eliminated from the revenue requirement computation in this case. The Company is rebasing the net base fuel costs in the FAC.

Staff Expert/Witness: Kofi Agyenim Boateng

B. Off-System Sales and Transmission Revenue

1. Off-System Sales

a. Energy

Off-system sales (OSS) are those sales of electricity made after Ameren Missouri has met all obligations to serve its native load customers (retail and full requirements wholesale customers). This excess energy is then available to sell to other utilities. By engaging in OSS, Ameren Missouri generates profits or net margin, which represents total proceeds from the sales less associated generation or purchased power cost. It is appropriate to include OSS in the cost of service because Ameren Missouri’s customers are already paying for all the costs associated with the generating facilities that produce electricity, as well as the purchased power that is necessary to meet native load. To the extent that OSS are made using these facilities, as well as by purchasing power, the customers should benefit from these sales. OSS represents an efficient utilization of the electric facilities/system that has been put in place to meet the electricity needs of Ameren Missouri's customers.

OSS revenues were calculated in the production cost model by using the hourly market energy prices that were determined by Staff witness Erin L. Maloney of the Commission's Energy Department. Staff's adjustment for OSS revenue represents the inclusion of additional revenue in order to annualize the OSS revenues that were calculated by Staff witness David W. Elliott using the RealTime™ production cost model. This adjustment was recorded in Staff's revenue requirement cost of service calculation by subtracting Ameren Missouri's test year ending March 31, 2010, per book OSS revenues from Staff's annualized level of OSS revenues as determined by the production cost model.

Staff will continue to examine OSS revenues through February 28, 2011, which represents the true-up cut-off date as approved by the Commission as part of this rate proceeding.

Staff Expert/Witness: Lisa K. Hanneken

b. Capacity Sales

Ameren Missouri sells capacity to other utility companies when it is not needed to serve its own load. Staff also included an adjusted level of capacity sales as part of the cost of service calculation in order to reflect actual capacity sales during the twelve months ending November 30, 2010. Staff will re-examine the level of capacity sales as part of its true-up audit.

Staff Expert/Witness: Lisa K. Hanneken

2. MISO Day 2

a. Revenues

Ameren Missouri participates in the Midwest Independent Transmission System Operator (MISO) activities (often referred to as Day 1, activities prior to April 1, 2005, or "pre-Market") and the MISO day-ahead and real-time energy markets (often called MISO Day 2 or "Midwest Markets"). As part of its participation in the MISO Day 2 markets, during the test year the Company received payments from the MISO related to the Revenue Sufficiency

Guarantee (RSG) provision of MISO's tariff. These payments are designed to ensure that companies participating in the MISO Day 2 markets recover start-up and no-load costs in the event that the market price received does not cover these costs.

Start-up costs are the costs associated with bringing a generation unit on-line. No-load costs are the costs incurred by a generation unit, after start-up, but prior to providing any output. These two components are the fixed costs of running a generation unit.

The market price will always cover the Company's offer price for energy, but in some instances it may not cover the fixed costs of running the unit that are also submitted as a part of Ameren Missouri's offer price. When the Company's total offer prices are not covered by the market prices, Ameren Missouri receives RSG payments. For Ameren Missouri, the RSG payments received from MISO during the test year totaled $4,791,738.

The RSG payments are funded by billings to market participants based on their loads. Thus, Ameren Missouri is billed for RSG payments as a Day 2 market expense, and these expenses were included in the Staff's revenue requirement cost of service.

Both Ameren Missouri's and the Staff's models will not dispatch a unit to make sales unless the market price is sufficient to cover start-up and no-load costs. However, these models are based on costs, not offer prices which may be higher than costs. When the offer price is higher than cost, Ameren Missouri does not require revenue from off-system sales to cover the difference between revenues received from the market prices and revenues required to cover the offer prices.

On the other hand, if the RSG payments were only make-whole payments that covered only the difference between the cost of running the units and the market price received, then the Staff's production cost model results would be consistent with excluding all RSG payments received from MISO by Ameren Missouri. If the RSG payments only covered cost, then there would be no profit received by Ameren Missouri from actually running a generation unit at times when the production cost model would not dispatch the unit. However, RSG payments cover offer prices made by market participants and those offer prices can include adders to costs. To the extent that Ameren Missouri made offers that are above its costs, the RSG payments more than cover costs, they also include a contribution to profit that is not included in the Staff's modeling of net production costs. It is the understanding of the Staff, that offer prices of generation from the Company's gas-fired combustion turbine generators include an adder to cost.

Therefore, a portion of the RSG payments related to start-up and no-load costs should be eliminated from test year revenue because they relate to recovery of the Company's costs, but the portion related to the difference between the costs and offer prices should not be removed as this represents profit that the Company receives from its participation in the MISO Day 2 market. It is important not to exclude this profit, as the Company must make RSG payments to other companies through MISO to not only cover their start-up and no-load costs, but to also cover their offers that include a margin for profits. However, during the twelve months ending January 31, 2010, the cutoff date for its true up filing in File No. ER-2010-0036, Ameren Missouri's calculation indicated that there was no margins embedded in the RSG make whole payments. The Staff will re-examine this issue through February 28, 2011 during its true-up audit.

Staff Expert/Witness: Kofi Agyenim Boateng

b. Amortization of RSG Resettlement Expenses

Consistent with the Commission's Report And Order in Case No. ER-2008-0318, and File No. ER-2010-0036, relating to MISO resettlement charges, the Staff has included an amortization of previously incurred RSG resettlement expense. However, the amount of the Staff's amortization, $1,869,846, reflects the remaining balance (unamortized portion) of the RSG resettlement cost as of July 31, 2011, the effective date of rates in the current case.

Staff Expert/Witness: Kofi Agyenim Boateng

3. Transmission Revenue and Expense

The Staff is recommending adjustments to the test year level of MISO transmission revenues. These adjustments eliminate test year revenues that are non-recurring and revenue associated with a billing error. The adjustments also increase the level of revenue to annualize the test year period. In June 2010, MISO implemented new and higher rates for Ameren Missouri's Schedule 2 revenue, reactive supply and voltage control. Thus, the test year of twelve months ending March 31, 2010 per books do not reflect a full year of the additional revenues. Staff has annualized the test year's Schedule 2 revenue by using the actual amounts received in June 2010 through December 2010, which represent the first six months under the new rates. The Staff is also recommending an adjustment to the level of test year

MISO transmission expense to eliminate the expenses that are non-recurring and those associated with billing adjustments.

Staff Expert/Witness: Kofi Agyenim Boateng

4. Ancillary Services Market Revenue and Expense

Ameren Missouri also participates in MISO's "Day-3" market which has real time and day-ahead energy markets and an Ancillary Services Market (ASM). Ameren Missouri entered the ASM to acquire ancillary services for its retail load and to be able to sell the services from its generation. The MISO "Day-3" market was started in January 2009. The Staff has annualized ASM revenues and expenses by using the actual revenues and expenses for January 2010 through December 2010. The Staff will continue to review Ameren Missouri's ASM transactions as additional information becomes available through the true-up period.

Staff Expert/Witness: Kofi Agyenim Boateng

C. Miscellaneous Revenues

1. SO_2 Allowance Sales and Tracker

As part of Report and Order issued in Case No. ER-2007-0002, the Commission established an accounting mechanism to track Ameren Missouri's SO_2 emission allowance sales revenues net of SO_2 expenses. The Company realizes SO_2 revenues from gains on the sale of SO_2 emission allowances. SO_2 expenses are realized from the premiums paid, net of the discounts received, as a result of SO_2 content variations from the terms of the contacts through which Ameren Missouri purchases its coal supply and the coal actually received. Beginning on January 1, 2007, the Company was required to account for all SO_2 premiums, net of any SO_2 discounts, in a regulatory liability account. The Commission also ordered that all gains from SO_2 allowance sales, in excess of $5,000,000, be recorded in this same regulatory liability account.

This regulatory liability account, referred to as the SO_2 Tracker, also accumulates interest at Ameren Missouri's short-term borrowing rate. This SO_2 tracker was continued as part of Case No. ER-2008-0318, however, as a result of the last rate proceeding File No. ER-2010-0036, the SO_2 tracker was discontinued. In the future, the cost associated with the SO_2 premiums, net of discounts, and the revenues from gains on the sale of SO_2 emission allowances will be included in Ameren Missouri's Fuel Adjustment Clause. Therefore, Staff is removing all revenues related to SO_2 emission allowances from its Cost of Service calculation. In addition, Staff is recommending the following regarding the cost associate with the SO_2 premiums, net of discounts accumulated in the tracker prior to the 6/21/2010 effective date of rates in File No. ER-2010-0036.

After the January 31, 2010 true-up cut-off, but prior to the June 21, 2010 effective date of new rates in ER-2010-0036, the SO_2 tracker continued to accumulate costs. At January 31, 2010, the true-up date in File No. ER-2010-0036, the Company had a SO_2 regulatory asset balance of $19,546,195. For all activities that occurred during the subsequent period of February 1, 2010 through June 20, 2010, the Company's SO_2 tracker balance represented an additional regulatory asset of 2,911,427. These tracked amounts total $22,457,622. As part of rate Case No. ER-2008-0318, the Commission approved an amortization amount of $355,590 per month related to the SO_2 regulatory asset balance. And as part of rate File No. ER-2010-0036, the Commission approved amortization amount was $518,100 per month. During the effective periods of these amortizations, from March 1, 2009 to June 20, 2010, and June 21, 2010 to July 31, 2011, the total amount included in rates through these monthly amortizations was $12,478,908.

Staff is recommending that the remaining tracked amount not reflected in rates as of the effective date of rates in the current case, $9,978,715 ($22,457,622 less $12,478,908) be amortized over a period of two years at a rate of $4,989,358 annually. As a result, Staff included an additional $722,278 in the cost of service calculation, above the $4,267,079 included in the test year, to reflect a two year amortization for this balance.

Staff Expert/Witness: Lisa K. Hanneken

D. Fuel and Purchased Power Expense

Staff's annualized and normalized fuel and purchased-power expense is sufficient to serve native load and make OSS. Staff's fuel expense adjustment includes all increases in commodity coal and coal transportation costs based upon contracted coal and transportation costs in effect through February 28, 2011. Staff's fuel expense adjustment for nuclear fuel is based upon a 5-month average of prices that occurred during the period covering July 1, 2010 through November 30, 2010 as provided by Company in its response to Staff Data Request Nos. 43 and 74. Staff's fuel expense annualization also incorporates natural gas and fuel oil prices as sponsored by Staff witness Erin L. Maloney. Staff also included in the fuel cost calculation the fixed demand cost of natural gas and a reduction resulting from fly ash activities. Staff has excluded from its fuel and purchased power annualization all costs incurred during the test year associated with the fuel additive magnesium oxide, since Ameren Missouri has no plans to continue using this fuel additive at any of its coal units and has not made any purchases of this product since October 2009. Staff's annualized purchased power expense levels reflect prices sponsored by Staff witness Erin L. Maloney.

The Staff used the RealTime™ production cost model to determine its annualized and normalized level of fuel and purchased power expense. In addition to the annualized and normalized prices, the RealTime™ inputs include normalized hourly net system loads as well as modeling information about Ameren Missouri's various generating units. OSS were also modeled using RealTime™ production cost model and the revenues from these OSS were netted against the fuel and purchased power costs in order to calculation Staff net bare fuel costs. Additional information regarding the RealTime™ production cost model and its inputs will be discussed and sponsored by Staff witness David W. Elliott later in this report.

Staff Expert/Witness: Lisa K. Hanneken

1. Fuel and Purchased-Power Prices

Staff reviewed all of Ameren Missouri's coal commodity and coal transportation contracts. Staff reviewed nuclear, natural gas and fuel oil prices as reflected in Company fuel reports, workpapers and responses to Staff data requests. Staff's fuel expense adjustments reflect all known increases in commodity coal and coal transportation costs that will be in effect as of February 28, 2011. Staff's fuel expense adjustments also reflect actual known and measurable nuclear fuel prices through November 30, 2010. Staff will continue to examine all of these fuel cost components through the true-up period ending February 28, 2011 in order to address any significant changes.

Staff Expert/Witness: Lisa K. Hanneken

a. Coal prices

i. Accounting Coal Prices

Staff's accounting coal prices are used to compute the fuel costs based on the coal unit generation that is determined by the production cost model. Staff performed a review of all of Ameren Missouri's current accounting coal commodity and coal transportation contracts. Staff's accounting coal prices reflect Ameren Missouri's mine specific coal commodity and coal rail and barge transportation contracts that will be in effect as of February 28, 2011. Staff also included an ongoing level of cost associated with hedging for the cost of rail transportation fuel surcharges that are tied to the prices of on-highway diesel as reported by the Energy Information Administration, an independent statistical agency of the US Department of Energy. Staff included all railcar related costs as a component of the accounting coal price used in the production cost model.

Staff Expert/Witness: Lisa K. Hanneken

ii. Dispatch Coal Prices

For the purposes of Staff's cost-of-service report the coal dispatch prices per plant developed by the Company were used to develop a single annual coal dispatch price per plant. This annual coal dispatch price was then used in the Staff's fuel model. Staff used this approach because neither the dispatch coal prices calculated by Staff using the data provided by the Company in response to Data Request No. 63 nor the dispatch coal prices calculated using the data provided as per 4 CSR 240-3.190 reporting requirements appeared to be reasonable. For example, this information yielded dispatch prices that placed the Meramec plant dispatching ahead of Labadie and Rush Island. However, the Staff will meet with Company to discuss this issue further and will also continue to review actual coal dispatch prices for the various generating units through the true-up period ending February 28, 2011 and will make adjustments to its coal dispatch prices as necessary.

Staff Expert/Witness: Erin L. Maloney

b. Nuclear Fuel Prices

Ameren Missouri refueled its Callaway nuclear power plant during April through June of 2010. In order to reflect the nuclear fuel prices associated with this new refueling, Staff used a 5-month average price of the actual nuclear fuel prices for the period ending November 2010 provided by Company in its response to Staff Data Request Nos. 43 and 74. Staff also included costs associated with the disposal of spent nuclear fuel. Staff will re-examine the nuclear fuel prices as part of its true-up audit and make any adjustments deemed appropriate.

Staff Expert/Witness: Lisa K. Hanneken

c. Natural Gas Prices

i. Variable Natural Gas Cost

The Staff analyzed natural gas prices over a three-year period using data provided in response to Staff Data Request No. 62. Staff calculated the average system price per month using the three years of monthly data ending July 31, 2010. Twelve (12) monthly gas prices were used as input to the production cost model. Staff will continue to review natural gas prices through the true-up period ending February 28, 2011 and will make adjustments as necessary.

Staff Expert/Witness: Erin L. Maloney

ii. Fixed Natural Gas Cost

Staff adjusted expenses to include the fixed demand cost of gas in its revenue requirement cost of service. This amount must be added to Staff's production cost model results which are based on only the variable commodity cost of gas.

Staff Expert/Witness: Lisa K. Hanneken

d. Oil Prices

Fuel oil plays a very small part in the total fuel costs of Ameren Missouri. The fuel oil price was calculated as the 36 month average of the monthly average fuel oil prices provided in response to Staff Data Request No. 85. The three year period ending July 31, 2010 was used. A single fuel oil price was used in the production cost model. Staff will continue to review oil prices through the true-up period ending February 28, 2011 and will make adjustments as necessary.

Staff Expert/Witness: Erin L. Maloney

e. Purchased Power Prices

The Staff analyzed three years of hourly power prices using the power transactions provided as submitted to the Staff per the 4 CSR 240-3.190(1)(E) monthly reporting requirements for the period ending July 31, 2010. Staff developed hourly average market prices weighted by the actual sales and purchases made by Ameren Missouri during each hour in this period. Staff calculated weighted average monthly prices for each month in the three year period ending July 31, 2010 and then developed factors for each month based on the twelve months ending July 31, 2010 and the three year monthly averages. The day ahead prices that occurred in the twelve months ending July 31, 2010 were then adjusted by these factors. The resulting 8,760 hourly prices were then used as input to the production cost model. Staff will continue to review market energy prices through the true-up period ending February 28, 2011 and will make adjustments as necessary.

Staff Expert/Witness: Erin L. Maloney

2. Potential Refundable Entergy Charges

In Case No. ER-2008-0318, Ameren Missouri agreed to the following as reflected and approved by the Commission in its Report and Order:

> The company shall maintain such books and records as are necessary to allow the Staff to identify the amount of refunds, if any, the company may receive in the future arising from the dispute involving the 1999 purchased power service agreement with Entergy Arkansas described in the surrebuttal testimony of Staff witness John P. Cassidy. The company shall also maintain the books and records necessary to identify any costs associated with obtaining any such refunds such as legal expenses associated with efforts to obtain refunds. (page 56., Jan. 27, 2009).

Furthermore, item 30, found on page 10 of the First Non-Unanimous Stipulation and Agreement reached in File No. ER-2010-0036, and approved by this Commission, states the following: "AmerenUE shall continue to adhere to the Commission's Report and Order from Case No. ER-2008-0318 regarding tracking potential refunds of Entergy Charges."

As part of a former purchased power agreement with Entergy that expired in August 2009, Ameren Missouri made payments for pass-through equalization charges that it has since disputed. Ameren Missouri filed an appeal with the Federal Energy Regulatory Commission (FERC) and has the potential to receive a refund for these payments based upon a pending ruling by the FERC. Payment for these disputed equalization charges were reflected in rates as part of Ameren Missouri, Case No. ER-2008-0318. In addition all legal costs that Ameren Missouri incurred to address this matter were included in Ameren Missouri's rates as part of the last two rate case proceedings, ER-2008-0318 and ER-2010-0036. As part of the current rate proceeding, the Staff has included as part of its overall cost of service calculation all legal costs to deal with this ongoing Entergy matter that was incurred by Ameren Missouri during the test year ending March 31, 2010. Because these costs have been included in the determination of rates for Ameren Missouri in all previous rate proceedings and are therefore being paid for by Ameren Missouri ratepayers, it is appropriate for those ratepayers to benefit from any future refunds that may occur in relation to these costs. To date Ameren Missouri indicates that it has not received a ruling from FERC regarding this matter and therefore has received no refunds. The Staff will continue to examine this area through the true-up period ending February 28, 2011, to determine if additional adjustments will be necessary to address any refunds. If no refunds are received by Ameren Missouri through the end of true-up in the current rate proceeding, the Staff will address this issue as part of Ameren Missouri's next general rate proceeding.

Staff Expert/Witness: John P. Cassidy

3. Production Cost Modeling

a. Variable Cost

The Staff estimates the variable fuel and purchased power expense for Ameren Missouri for the modified year, as defined in the Rate Revenue Section of Staff's Cost of Service Report, ending July 31, 2010 to be $444,427,710 with off-system sales, and $634,073,144 without off-system sales.

The Staff used the RealTime™ production cost model to perform an hour-by-hour chronological simulation of Ameren Missouri's generation and power purchases. The production cost model determines the annual variable cost of fuel and purchased power to economically match Ameren Missouri's hourly electric load within the operating constraints of its resources. These results are supplied to Auditing Staff who use this input in the annualization of fuel expense.

The model operates in a chronological fashion, matching each hour's energy demand before moving to the next hour. The model schedules generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operation constraints. The model closely simulates the way a utility should dispatch its generating units and purchase power to match the net system load in a least cost manner.

Inputs provided by the Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. For generating unit data, the Staff relied on the company's direct testimony, responses to data requests, workpapers provided by Ameren Missouri witness Tim Finnell, and data Ameren Missouri supplied to comply with 4 CSR 240-3.190. The generating unit data include the capacity of the unit, the unit heat rate curves, the primary and startup fuels, the ramp-up rate, the startup costs, and the fixed operating and maintenance expense. The energy price from Ameren Missouri's wind power contract with Horizon Pioneer Prairie was also an input to the model.

The Staff model was benchmarked by using Ameren Missouri's model inputs. The difference between Staff's model benchmark results and the Ameren Missouri model results that support Tim Finnell's direct testimony was less than 0.20%.

For this rate case the model was run with and without off-system sales to estimate the level of off-system sales.

Staff Expert/Witness: David W. Elliott

b. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the Ameren Missouri generating unit outages were normalized by averaging the seven years (2003 through 2009) of actual values taken from responses to data requests, and data Ameren Missouri supplied to comply with 4 CSR 240-3.190.

Staff Expert/Witness: David W. Elliott

c. Capacity Contract Prices and Energy

Capacity contracts are contracts for a specific amount of capacity (megawatts) and a maximum amount of hourly energy (megawatt hours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. The capacity contract in this case consisted of the Horizon Pioneer Prairie wind contract.

Actual hourly contract transaction prices were obtained from the Horizon Pioneer Prairie contract provided by Ameren Missouri. The hourly energy was developed by averaging the actual hourly energy in 2010 and the projected energy from Ameren Missouri workpapers.

Staff Expert/Witness: David W. Elliott

4. Normalization Of Hourly Net System Load

Hourly net system load is the hourly electric supply necessary to meet the energy hourly demands of both the company's customers and the company's own internal needs. It is net of (i.e., does not include) station use, which is the electricity requirement of the company's generating plants.

Due to the presence of air conditioning and the presence of significant electric space heating in Ameren Missouri's service territory, the magnitude and shape of Ameren Missouri's net system input is directly related to daily temperatures. Actual and normal daily temperatures provided by Staff witness Dr. Seoung Joun Won were used in the analysis. The actual daily temperatures for the modified year period differed from normal daily temperatures. Therefore, to reflect normal weather, daily peak and average net system loads are each adjusted independently, but using the same methodology.

Daily average load is the daily energy divided by twenty-four hours and the daily peak load is the maximum hourly load for the day. Separate regression models are used to estimate both a base component, which is allowed to fluctuate across time, and a weather sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. Independent regression models are necessary because daily average loads respond differently to weather than peak loads do. The model's regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added respectively to the actual average load and to the peak load of each day. The starting point for allocating the weather-normalized daily peak and average loads to the hours is the actual hourly loads for the year being normalized. A unitized load curve is calculated for each day as a function of the actual peak and average loads for that day. The corresponding weather normalized daily peak and average loads, along with the unitized load curves, are used to calculate weather normalized hourly loads for each hour of the year.

This process includes many checks and balances, which are included in the spreadsheets that are used by Staff. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[29]

An adjustment was made to the Large Transmission Service class' load to help the total system shape coincide with the annualization adjustment to revenues of Staff witness Dr. Seoung Joun Won.

To produce an annual sum of the hourly net system loads consistent with Staff's normalized revenues, average annual losses are added to the weather-normalized and annualized usage for Ameren Missouri's retail customer classes and weather-normalized wholesale usage.

A factor was applied to each hour of the weather-normalized net-system loads to produce an annual sum of the hourly net-system loads that equals the usage, plus losses that is consistent with normalized revenues. Once completed, the hourly normalized system loads were given to Staff witness David W. Elliott to be used in developing fuel and purchased power expense. Staff witness Alan J. Bax also used the annual requirement of the net system load in developing the Staff's jurisdictional energy allocator.

Staff Expert/Witness: Shawn E. Lange

5. Losses

The basis for calculating system energy losses is that Net System Input (NSI) equals the sum of "Total Sales" and "System Energy Losses." This can be expressed mathematically as:

NSI = Total Sales + System Energy Losses

NSI and Total Sales are known, metered values; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales

The system energy loss percentage is the ratio of system energy losses to NSI multiplied by 100:

System Energy Loss Percentage = (System Energy Losses ÷ NSI) X 100

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[29] Weather Normalization of Electric Loads, Part A: Hourly Net System Loads" (November 28, 1990), written by Dr. Michael Proctor, Manager of the Economic Analysis Department

NSI is also equal to the sum of the Company's net generation and net interchange. Net interchange is the difference between off-system purchases and sales. Net generation is the total energy output of each generating plant minus the energy consumed internally to enable the production of electricity at each plant. The output of each generating plant is monitored continuously; as is the net of off-system purchases and sales.

Historically, NSI was considered to be calculated "at the generator" level, at the generation/transmission interface. Therefore, system energy losses included all associated losses between Ameren Missouri's generation sources and its customers' meters. However, the data provided by Ameren Missouri in this case and utilized by Staff in its calculation of NSI was reported at the Company's transmission/distribution interface, that is, the value of NSI no longer includes losses experienced by Ameren Missouri on its transmission system. Hence, with NSI being reported at the transmission level in lieu of the generation level, then system energy losses Staff calculated are at the transmission level instead of the generation level.

Staff calculated a loss percentage of 4.94% of NSI for the twelve month period ending July 2010. Staff's calculated loss percentage is being used by Staff witness Shawn E. Lange in the development of hourly loads used in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

<u>6. Other Fuel Related Items</u>

a. Westinghouse Credits

During the test year ending March 31, 2010, the Company received credits from Westinghouse as part of a prior settlement of a uranium supply contract dispute. Staff included an annualized level of credits in the cost of service based on the monthly amount currently being experienced since the last Callaway refueling.

Staff Expert/Witness: Lisa K. Hanneken

b. Fuel Additive

Staff adjusted the cost of service calculation to remove all costs incurred during the test year related to Company's use of the fuel additive Urea. The Company has indicated that it is currently not using the additive and has no definite plans to do so in the future.

Staff Expert/Witness: Lisa K. Hanneken

c. Limestone for Sioux Scrubbers

The Company recently installed SO_2 scrubbers at the Sioux plant. As a result, a supply of limestone must be provided to the plant in order to operate the scrubbers. The limestone provided must meet certain standards of quality and be put through a pulverization process in order to be utilized in the scrubbers. Therefore, the Company has contracted with three vendors in order to obtain a supply of limestone with the proper specifications. The Company contracted with a quarry which supplies the correct grade of limestone, a processor which operates the processing facility onsite at the quarry, and a trucking company which has the required equipment to transport the processed limestone to the Sioux facility. There are many variables within each contract including surcharges for different items. The Company and Staff each estimated the cost level associated with the amount of limestone required to achieve a 95% SO_2 removal rate. An estimated level was required due to the fact that there is limited historical data regarding these costs. Staff is also aware that the Company's transportation contract expired in December 2010 and that the limestone contract is being renegotiated. Staff has reviewed a draft of a contract with a new transportation company and a supplement to the limestone contract, both of which have been agreed to by the Company and its vendors, but have not been finalized and presently remain unsigned. However, Staff has utilized the terms in these drafts in its calculations based on discussions with the Company that indicate the terms of the contract will be finalized as reflected in the drafts. Therefore, Staff made adjustments to include only the estimated amount of limestone which would be required to achieve the 95% removal rate at the current draft contract terms. Staff is recommending an ongoing level for limestone expense of $2,789,716.

Because there is very little history for this cost, Staff will review the new contracts once they are finalized and reexamine this issue as part of its true-up analysis.

Staff Expert/Witness: Lisa K. Hanneken

E. Payroll and Benefits

1. Payroll

Staff's annualized payroll is based upon the test year ending March 31, 2010, actual Missouri electric related payroll expense adjusted for the following: a) inclusion of the lump sum amortization applicable to union contract employees, b) increases in wage rates that have occurred since the true-up cutoff date in the Company's last rate case, c) increases and reductions in the level of ongoing management and contract Ameren Missouri employees and Ameren Services employees that allocate costs to Ameren Missouri through January 1, 2011, and d) the reduction of payroll expense resulting from a reduction of employees due to a voluntary separation election plan (VSE) and an involuntary separation program (ISP) that was implemented by the Company during the latter part of 2009. After allocating a portion of Ameren Missouri electric related payroll to construction, the Staff's adjustment for payroll expense was distributed by account based on the actual payroll distribution experienced by the Company during the test year ending March 31, 2010. The Staff's Accounting Schedule 10, "Adjustments to Income Statement," reflects approximately 73 adjustments in order to restate test year payroll expense to an annualized level. The Staff has also reflected in Accounting Schedule 10, five additional adjustments, consistent with Company's treatment, in order to normalize overtime associated with periodic Callaway nuclear facility refuelings.

By including January 1, 2011, actual employee levels, Staff's payroll annualization effectively addresses all changes pertaining to any additional labor costs associated with the newly reconstructed Taum Sauk facility, the addition of the new scrubbers at the Company's Sioux power plant facility as well as any distribution line training costs. As part of its true-up audit, the Staff will re-examine payroll and all Ameren Services related costs that are allocated to Ameren Missouri, that may have been impacted by the recent changes in employee levels, in order to determine whether any further adjustments to the cost of service are necessary.

Staff Expert/Witness: John P. Cassidy

2. Payroll Taxes

The Federal Insurance Contributions Act (FICA) Old Age Survivors and Disability Insurance (OASDI) and FICA Medicare payroll taxes were annualized by applying the respective payroll tax rates to Staff's annualized payroll adjustment, which reflects an overall reduced level of employees that exists at January 1, 2011. Staff also removed from the cost of service calculation all Federal Unemployment Tax Act (FUTA) and State Unemployment Tax Act (SUTA) taxes paid during the test year for employees that are no longer with the Company. Finally, during December 2009, the Company incorrectly recorded the allocation of payroll taxes between its electric and gas company books. As a result of this incorrect entry, Ameren Missouri's electric per book payroll taxes are understated for the 12 months ending March 31, 2010, by approximately $1.2 million. The Staff's total payroll tax adjustment includes this amount in order to increase the level of payroll taxes that are reflected in the cost of service calculation by approximately $1.2 million to properly reflect the correct amount applicable to electric operations during the test year.

Staff Expert/Witness: John P. Cassidy

3. Voluntary Separation Election Plan and Involuntary Separation Program

During September 2009, Ameren offered a VSE to management employees. In addition during November 2009, Ameren implemented an ISP. Several Ameren Missouri and Ameren Services management employees' positions were permanently eliminated through the implementation of each of these two programs. Since these programs occurred during the test year ending March 31, 2010 as established by the Commission in the current rate proceeding, Staff has made adjustments to the cost of service calculation in order to normalize and annualize the affects of VSE and ISP.

Staff Expert/Witness: John P. Cassidy

4. Test Year Severance Costs and Amortization of Severance Costs

In File No. ER-2010-0036, a three year amortization was established for the $7.05 million of estimated severance cost associated with the VSE and ISP programs at the true-up cutoff date, January 31, 2010. The amortization of these costs began on the June 21, 2010 effective date of rates as established in the last rate case and no portion of these costs were recorded on the Company's books during the test year ending March 31, 2010, of the current case. Therefore, the Staff included an approximate $2.35 million adjustment in the cost of service calculation in this case in order to reflect a full year of severance cost amortization as approved by the Commission in File No. ER-2010-0036.

As part of its review of these costs in the current rate proceeding, the Staff discovered that actual severance costs incurred during the test year of the current case, in relation to the VSE and ISP, was approximately $7.6 million. The Staff made an adjustment to remove this

$7.6 million of actual test year severance costs from its cost of service calculation, consistent with the Company. However, this $7.6 million of test year severance costs represents an amount that is $546,553 more than the $7.05 million that is currently being amortized over three years as part of the last rate case. Therefore, in the current case, the Staff is proposing to amortize this additional $546,553 of severance costs over a two year period, beginning with the effective date of rates established in this rate case proceeding. This shortened two year recovery period provides a very similar recovery timeframe for these additional severance costs that were not addressed as part of the Company's last rate case. The Staff has included an adjustment of $273,277 in the cost of service calculation in this case to reflect its proposed amortization of this additional severance cost.

Staff Expert/Witness: John P. Cassidy

5. Accounting Standards Codification 715-30 (formerly FAS 87) Pension Costs

a. Accounting Standards Codification 715-30 Pension Tracker

Staff, Ameren Missouri and other parties entered into a Stipulation and Agreement ("the 2007 Agreement") in Case No. ER-2007-0002 that addresses the ratemaking treatment for annual qualified pension cost under Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Subtopic 715-30 (formerly FAS 87). The 2007 Agreement requires Ameren Missouri to fund its annual pension expense and track the difference between the annual pension expense and the level included in rates. The difference between the annual pension cost and the amount included in rates, as accumulated in the tracker, has been included in rate base and amortized over a period of five years as an addition or reduction to pension expense. Based on information provided in a response to Staff Data Request No. 0137 in File No. GR-2010-0363, and discussions with the Company in that case, it came to Staff's attention that Ameren Missouri is not funding the non-qualified portion of its pension expense. Ameren Missouri states that the non-qualified plan is unfunded, and that the plan benefit payments are made on a monthly disbursement basis. With this information and the Company's response to Staff Data Request No. 0354 in File No. ER-2011-0028, Staff has proposed an adjustment to remove $3,099,975 from Ameren Missouri's rate base tracker for the non-qualified pension expenses included in rates, in excess of amounts paid, that are included in the tracker since June 2007 through December 2010. This calculation is reflected in Appendix 3, Schedule KAB-3. Staff proposes that pension tracker only include amounts associated with funded qualified pension expense. Consistent with the Stipulation and Agreement in Case No. ER 2007-0002 and subsequent Ameren Missouri's rate cases, and Staff's proposed adjustment for non-qualified pension expense discussed above, the Staff's rate base for Ameren Missouri is reduced for a regulatory liability in the amount of $1,593,985, which represents the over collection in rates of Subtopic 715-30 pension expense, compared to the actual expense and funding incurred. This amount is the net of $4,957,404, which represents a regulatory asset in this current rate case, plus $3,500,942, which represents the unamortized portion of the regulatory asset in File No. ER-2010-0036, less $6,952,355, which represents the unamortized portion of the regulatory liability in Case No. ER-2008-0318, and the proposed adjustment to reduce the pension tracker by $3,099,975, which represents non-qualified pension expense. All of these amounts with the exception of the adjustment for the non-qualified pension expense were calculated taking into consideration the estimated balances projected as of February 28, 2011, the end of the true-up period. Staff has also included a total reduction to pension expense in its income statement in the amount of $1,138,056, for annual amortization, over five years, of the amount accumulated in the Subtopic 715-30 pension tracker in this rate case and amortized amounts from the previous rate cases.

To account for federal changes to pension plans since the pension and Other Post Retirement Benefit Costs (OPEBs) tracker was originally introduced, Staff has proposed the new language for the Tracker for Pension and OPEBs that is reflected in Appendix 3, Schedule KAB-4.

Staff Expert/Witness: Kofi Agyenim Boateng

b. Annualization

Staff also annualized pension expense to reflect the projected FASB ASC Subtopic 715-30 cost provided by Ameren Missouri's actuary for qualified pension plans. This level is the Staff's recommendation for the amount used in the pension tracker, after rates are established in this case, to determine the difference between pension expense included in rates and the amount actually incurred and funded by Ameren Missouri for qualified pension expense.

Additionally, the Company's pension expense includes the cost related to non-qualified pension plans described as the Ameren Supplemental Retirement Program, which is designed for selected Ameren Missouri executives. Since this plan is not funded, only the actual payments made during the test year were used as expense for this retirement program. Since some of Ameren Missouri's management and administrative functions are provided by AMS employees, Ameren Missouri's pension expense includes costs that are allocated from AMS.

Staff Expert/Witness: Kofi Agyenim Boateng

6. Accounting Standards Codification ("ASC") 715-60 (formerly FAS 106) Other Post Retirement Benefit Costs (OPEBs)

a. ASC 715-60 OPEBs Tracker

The Agreement in ER-2007-0002 also addresses the ratemaking treatment for the annual OPEBs cost under Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") Subtopic 715-60 (formerly FAS 106). As with pension expense, the Agreement requires funding of the annual OPEB expense and establishes a tracker for the difference between the amount of OPEB expense in rates and the actual expense incurred. Consistent with the Agreement from Case No. ER-2007-0002, the Staff's rate base for Ameren Missouri is reduced for a regulatory liability in the amount of $44,784,619, which represents the over-collection in rates of ASC Subtopic 715-60 OPEBs expense, compared to the actual expense incurred. This amount reflects the addition of $18,369,729, which represents a regulatory liability in this rate case, the unamortized portion of the regulatory liability of $14,279,153, in Case No. ER-2010-0036, and $12,135,737, which represents the unamortized portion of the regulatory liability in Case No. ER-2008-0318. All of these amounts were calculated based on the estimated balances projected as of February 28, 2011, the end of the true-up period. The Staff has also included a total reduction to pension expense in its income statement in the amount of $6,226,525 for the annual amortization, over five years, of the amount accumulated in the ASC 715-60 OPEBs tracker.

b. Annualization

The Staff also annualized OPEB expense to reflect the projected ASC Subtopic 715-60 cost provided by Ameren Missouri's actuary, Towers Perrin. This level will be the amount used in the OPEB tracker, after rates are established in this case, to determine the difference between OPEB expense included in rates and the amount actually incurred and funded by Ameren Missouri. Since some of Ameren Missouri's management and administrative functions are provided by Ameren Services employees, Ameren Missouri's OPEB expense includes costs that are allocated from Ameren Services.

Staff Expert/Witness: Kofi Agyenim Boateng

7. Other Employee Benefits

The Company currently offers employees medical, dental, vision, life insurance, long-term disability and 401k benefits. The Staff has reflected in the cost of service the actual 12 months ending November 30, 2010, level of benefits. This November 30, 2010 level excludes all costs associated with employees that are no longer with the Company due to the VSE and ISP. The Staff adjusted this level to reflect the impact of all changes in employee levels that have occurred through January 1, 2011. The Staff will continue to analyze actual benefit cost information as it becomes available through February 28, 2011, which represents the true-up cutoff point established by the Commission in this rate proceeding. As a result of this continuing analysis the Staff may propose further adjustment to employee benefits as part of the true-up audit.

Staff Expert/Witness: John P. Cassidy

8. Short-Term Incentive Compensation

The Company has three distinct incentive compensation plans that are offered to employees: short-term incentive compensation, long-term incentive compensation, and an Exceptional Performance Bonus Program (EPBP). Some of Ameren Missouri's incentive compensation costs are allocated from Ameren Services, as Ameren Services provides various management and administrative functions to Ameren Missouri.

The short-term incentive compensation plan is broken -out into five categories as follows:

- Executive Incentive Plan - Officers,
- Executive Incentive Plan - Managers and Directors
- Ameren Manager Incentive Plan
- Ameren Marketing, Trading & Commodities, and
- Ameren Incentive Plan

The Executive Incentive Plan for Officers (EIP-O) is designed to incent officers of the Company to ensure that they are focused on the overall success of the Company's business.

These officers are senior level individuals who hold the positions of vice president, senior vice president, president and chief executive officer. The officers and the personnel with manager and director positions form the Ameren Leadership Team (ALT), a group that is responsible for the strategy and direction of all the functional areas within Ameren Missouri. Awards at this level are based upon the individual officer's personal performance and the achievement of certain scorecard key performance indicators (KPIs), as determined by the Company. Such KPI measures may include Ameren Missouri's earnings, safety, reliability, and/or customer satisfaction. The Company's EIP-O is entirely funded based on earnings per share (EPS), and has been disallowed by Staff.

The Executive Incentive Plan for Managers (EIP-M) is a plan designed for members of the ALT, below the Officers level. Much like the EIP-O, the EIP-M awards are based upon participant's demonstrated leadership and contributions toward the achievement of the Company's business objectives. However, unlike the EIP-O, the EIP-M funding is based twenty-five percent on EPS and seventy-five percent is based on operational performance. The Company measured operational performance by KPIs and individual performance, as determined by supervisors through the performance appraisal process. Staff has disallowed the twenty-five percent of the EIP-M that is EPS related.

The Ameren Manager Incentive Plan (AMIP) is designed for management employees and is funded entirely based on achievement of a set of KPIs. Like the EIP, payouts are based on the achievement of the participant's individual performance objectives and his/her contributions to the group's KPI measure. Similar to individual performance for the EIP-M, individual performance is determined by supervisors through the performance appraisal process. Staff has allowed the costs associated with this incentive program.

The Ameren Marketing, Trading & Commodities (AMTC) plan is similar to the AMIP and is designed to target management employees who perform specific roles within the Company's trading and fuel divisions. This plan has two components: one, the base plan, which is identical to the AMIP, and two, the second component, called supplemental plan which provides group or position-specific measures for individuals within this group to achieve. The awards under the supplemental plan are converted into units of stock and are held for two years for the purpose of promoting employee retention before they are paid out. Staff has allowed the costs associated with both components of this incentive program.

The Ameren Incentive Plan (AIP) is offered only to contract employees and funding is determined by attaining specified KPI goals. It is designed to focus employees on areas that they are able to control. Staff has allowed the actual costs associated with this incentive plan.

The EPBP, unlike the short-term incentive compensation plans, is not determined by either meeting a certain level of EPS or KPIs, but are awarded on the basis of outstanding performance of an individual as determined by his or her supervisor and approved by an officer. The process begins when a supervisor submits a recommendation, by completing a Performance Recommendation Form, to an officer that an employee be considered for a bonus on the basis of an exceptional performance. The supervisor who makes this recommendation also recommends the amount of bonus to be awarded. If this recommendation is approved, the employee is eligible for a bonus ranging from $500 to $4,000. However, Exceptional Performance Bonus awards are not expected to exceed 10% of the employee's annual base pay in any contract year.

The criteria the Staff uses to evaluate employee incentive plans were established in the Commission's Report and Order for *Re Union Electric Co.*, Case No. EC-87-114:

> At a minimum, an acceptable management performance plan should contain goals that improve existing performance, and the benefits of the plan should be ascertainable and reasonably related to the plan. 29 Mo. P.S.C. (N.S.) 313, 325 (1987).

The Staff has reviewed Ameren Missouri's incentive compensation plans as described above and recommends that all incentive compensations that are directly tied to EPS be disallowed from the cost of service. This recommendation is consistent with past Commission rulings. In its Report and Order in *Re Kansas City Power & Light Company*, Case No. ER-2006-0314, at page 58, the Commission noted that, among other things, "because maximizing EPS could compromise service to ratepayers, such as by reducing customer service or tree-trimming costs, the ratepayers should not have to bear that expense." Again, in the most recent Ameren Missouri rate case, Case No. ER-2008-0318, at page 92 of the Report and Order, the Commission decided that, "Ameren Missouri shall not recover in rates the cost of its long-term compensation plan," for its executive officers as the plan was based on earnings per share which in the Commission's view "primarily benefit shareholders and not ratepayers."

The Staff has made an adjustment to the test year incentive compensation expense consistent with the VSE and ISP which called for the elimination of certain management positions within Ameren Missouri and Ameren Services. Staff witness John P. Cassidy discusses the VSE and ISP in detail under that section of this Cost of Service Report.

In addition to the adjustment in the Operation and Maintenance (O&M) expenses, the Staff has made corresponding reductions in Ameren Missouri's plant in service and reserve balances to eliminate capitalized incentive compensation that relates to EPS. In concert with this belief that incentive compensation costs relating to EPS should be borne by ratepayers, the Staff has removed the incentive compensation that was capitalized from 2002 through the end of March 2010 from the plant in service and reserve balances.

Staff Expert/Witness: Kofi Agyenim Boateng

9. Long-Term Incentive Compensation: Restrictive Stock and Performance Share Units

In addition to the other compensation available (base and incentive), Ameren Missouri through its parent company Ameren Corporation (Ameren), also offers its executives the possibility of restrictive stock awards and performance share units, and these form the Company's long-term compensation plans. Conditions are placed on the receipt of restrictive stock awards related to earnings performance. The performance share units program is based on the market performance of Ameren's common stock relative to a peer group of other companies' common stock, over a three-year period. Consistent with the Company's treatment of not seeking recovery in retail rates of these long-term incentive plans, the Staff has eliminated all costs relating to these plans from its revenue requirement calculation.

Staff Expert/Witness: Kofi Agyenim Boateng

F. Other Expenses

1. Rate Case Expenses

The Staff examined what other large utilities in Missouri have spent in order to process recent rate cases. Staff then reviewed the actual costs from Ameren Missouri's previous rate case ER-2010-0036 and compared that to the estimated expenses for the current case. Based on this research, the Staff has determined that $1,000,000 should be sufficient for Ameren Missouri to process File No. ER-2011-0028 through to its conclusion.

Staff Expert/Witness: Lisa M. Ferguson

2. Dues and Donations

The Staff reviewed the list of membership dues paid, and donations made, to various organizations that Ameren Missouri charged to its utility accounts during the test year. The Staff proposes adjustments to disallow various dues and donations that were included by Ameren Missouri in test year expenses. Such dues and donations were disallowed by the Staff because they were not necessary for the provision of safe and adequate service, and thus do not have any direct benefit to ratepayers. Allowing the Company to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of items disallowed by the Staff are amounts paid to Civic Progress or the Hawthorne Foundation.

In *Re: Missouri Public Service, a Division of UtiliCorp United, Inc.*, Case Nos. ER-97-394, et al., Report and Order, 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

> The Commission has traditionally disallowed donations such as these. The Commission finds nothing in the record to indicate any discernible ratepayer benefit results from the payment of these donations. The Commission agrees with the Staff in that membership in the various organizations involved in this issue is not necessary for the provision of safe and adequate service to the MPS ratepayers.

Staff also determined that a new ongoing expense level for membership to the Electric Power Research Institute was appropriate based on information provided by the Company. Staff did not include in its level any additional charges that were recognized as dues and donations charges within the 900 accounts. These charges were treated the same within the 900 accounts but were not removed and added to Staff's dues and donations work paper. In addition, Staff has requested to review any membership related items that have been allocated from the Corporate level. As of this direct filing, Staff has not had the ability to fully review these items. Staff will not propose an adjustment for direct filing but this item may be subject to future adjustment during true-up in this case.

Staff Expert/Witness: Lisa M. Ferguson

3. Edison Electric Institute Dues

According to information obtained from the Edison Electric Institute's (EEI's) website (www.eei.org), EEI is an association of investor-owned electric utilities and industrial affiliates. From the information concerning EEI reviewed by the Staff in this case, it is clear that part of EEI's function is to represent the interests of the electric utility industry in the legislative and regulatory arenas. By necessity, this role includes engagement in lobbying activities by EEI.

In Case No. ER-83-49, a KCPL rate increase case, 26 Mo.P.S.C. 104, 155 (1983), the Commission stated its position respecting EEI dues:

> …In the Company's last rate case, ER-82-66, the Commission reiterated its position that while there may be some possible benefit to the Company's ratepayers from Company's membership in EEI, the dues would be excluded as an expense until the Company could better quantify the benefit accruing to both the Company's ratepayers and shareholders.

This position has been re-affirmed by the Commission in subsequent rate proceedings.

In *Re: Kansas City Power & Light Co.*, Case Nos. EO-85-185 et al., Report and Order, 28 Mo.P.S.C. (N.S.) 228, 259 (1986), the Commission stated:

> . . . The argument that allocation is not necessary if the benefits lessen the cost of service to the ratepayers by more than the cost of the dues, misses the point.
>
> It is not determinative that the quantification of benefits to the ratepayer is greater than the EEI dues themselves. The determining factor is what proportion of those benefits should be allocated to the ratepayer as opposed to the shareholder. It is obvious that the interests of the electric industry are not consistently the same as those of the ratepayers. The ratepayers should not be required to pay the entire amount of EEI dues if there is benefit accruing to the shareholders from EEI membership as well. The Commission finds this to be the case. The Company has been informed in prior rate cases that it must allocate its quantified benefits from membership in EEI. That has not been done herein. Therefore, no portion of EEI dues will be allowed in this case.

Based on the above criteria and the lack of providing quantification of benefits on the part of the Company, the Staff disallowed the entire amount of EEI dues.

Staff Expert/Witness: Lisa M. Ferguson

4. Insurance Expense

a. Annualization

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of its customers) associated with unanticipated losses. The Staff annualized Ameren Missouri's insurance expense based on the most current premiums charged to the Company and included this level in its determination of revenue requirement in this case.

Staff Expert/Witness: Lisa M. Ferguson

b. Replacement Power

The Company had previously established a new policy of carrying additional coverage for replacement power insurance. This type of insurance protects the Company from loss due to the unavailability of generating plants when purchased-power costs surpass a price threshold. In response to Staff Data Request No. 38, the Company has indicated a reduced level of the actual ongoing premiums in expense due to depressed power prices. The lower cost is also a result of changing the terms of the policy. The Staff included the cost associated with this new premium in the cost of service in this case.

Staff Expert/Witness: Lisa M. Ferguson

c. Property Liability

The Staff's examination of insurance premiums for property liability revealed a significant increase since 2006. Based on discussions with the Company, Ameren Missouri has taken steps to reduce this cost. The September 2009-2010 premium increased over the 2008-2009 premium, but the 2010-2011 premium decreases to the levels of the 2008-2009 year premiums. The expense reflecting the 2010-2011 premium has been included in the determination of revenue requirement in this case.

Staff Expert/Witness: Lisa M. Ferguson

5. Vegetation Management And Infrastructure Inspection Programs

a. Annual Expense

The Staff adjusted the non-payroll test year expense level associated with Ameren Missouri's vegetation management and infrastructure inspections programs, to reflect the actual cost incurred during the twelve months ending November 30, 2010. The Staff will re-examine the actual cost through the end of the true-up period, February 28, 2011, to determine if further adjustment is necessary and/or appropriate. Staff recommends that the actual amount incurred for the 12 months ending February 28, 2011 also become the new base amount for tracking following the effective date of rates in File No. ER-2011-0028.

Staff Expert/Witness: Stephen M. Rackers

b. Trackers

ER-2008-0318

In Case No. ER-2008-0318, the Commission allowed Ameren Missouri to recover, over a three year period, the amount of costs the Company incurred to comply with the Commission's vegetation management and infrastructure inspection rules, in excess of the amount that was included in base rates from January 1, 2008 through September 30, 2008. In the following rate case, File No. ER-2010-0036, this amount was adjusted to account for a change in the amount included in base rates from January 1, 2008 through September 30, 2008. The Staff is recommending that the corrected amount that will be unamortized as of the effective date of rates in File No. ER-2011-0028, July 31, 2011, be included in expense. The Staff's recommendation will result in the amount of cost the Company incurred to comply with the Commission's vegetation management and infrastructure inspection rules, in excess of the amount that was included in base rates from January 1, 2008 through September 30, 2008 being fully reflected in rates during the twelve months ending July 31, 2012.

Also as part of Case No. ER-2008-0318, the Commission allowed Ameren Missouri to defer the amount of cost the Company estimated that it would incur to comply with the Commission's vegetation management and infrastructure inspection rules, in excess of the amount that was included in base rates from October 31, 2008 through February 28, 2009. An amount associated with this period was identified in File No. ER-2010-0036 and was offset against the over collection associated with the amount included in rates for the period March 1, 2009 through February 28, 2010. This net amount was ordered by the Commission to be amortized over three years. However, the amount previously identified in File No. ER-2010-0036 for the period March 1, 2009 through February 28, 2010 was based on an estimated amount for February 2010. The Staff replaced the February 28, 2010 estimated with the actual amount incurred and recalculated the amortization.

In addition, in Case No. ER-2008-0318 the Commission allowed Ameren Missouri to defer the amount of cost the Company estimated that it would incur to comply with the

Commission's vegetation management and infrastructure inspection rules, in excess of the amount that was included in base rates, $54.1 million and $10.7 million, respectively. However, during the 12 month period ending February 28, 2010, these amounts significantly exceeded the actual non-internal payroll costs incurred. This over recovery, adjusted for the actual expense realized in February 2010, was netted against the corrected amount deferred during the period October 1, 2008 through February 28, 2009.

ER-2010-0036

In File Number ER-2010-0036, the Commission ordered a new base for the tracker including vegetation and inspection cost of $50.39 million and $7.65 million, respectively. The amount reflected in rates, a combination of the new base established in File No. ER-2010-0036 and the previous base established in ER-2008-0318 will be compared to the actual amount incurred for the 12 months ending February 28, 2011 to identify any over or under collection. Consistent with the Commission's prior orders, Staff recommends that any over or under collection be amortized over a three-year period. To date, the actual amount incurred from March 2010 through November 2010 and the Staff's estimate of the levels for December 2010 through February 2011 are tracking evenly with the Commission ordered amount included in rates through February 2011. During the true-up, the Staff will replace its estimates to reflect the actual amount incurred during the 12 months ending February 28, 2011 and determine the existence of any over or under collection. Staff recommends a three year amortization for any amount of over or under collection.

Staff Expert/Witness: Stephen M. Rackers

<u>6. Customer Deposit Interest Expense</u>

See the discussion in Section VI. G., Rate Base-Customer Deposits.

Staff Expert/Witness: Lisa M. Ferguson

<u>7. Property Tax Expense</u>

For property assessment purposes, each utility company is required to file with its respective taxing authority a valuation of utility property at the beginning of each assessment year, which is January 1st. Several months later, based on the information provided by the utility, the taxing authority will in turn send the company what is known as "assessed values" for every category of the company's property. The taxing authority will issue to the utility company a property tax rate later in the year. The final step in the process is when the taxing authority issues a property tax bill to the company late in each calendar year with a "due date" of December 31st. The billed amount of property taxes is based on the property tax rate applied to the previously determined assessed values of the utility's plant in service balances as of January 1st of the same year. The Staff used the most recent property tax payments made in December 2010, plus increases for the additions of the scrubbers at the Sioux generating plant and enhancements at the Taum Sauk pumped-storage hydro plant.

Ameren Missouri is currently appealing the 2010 assessment of distributable property which is the basis of its December 31, 2010 payment. Ameren Missouri has paid the full amount of tax on this appealed assessment valuation, and an amount of $28,883,742 is currently being held in escrow. The Company has expressed to the Staff that it believes Ameren Missouri will prevail in its appeal. However, the culmination of this appeal will most likely not occur until after the true-up process. Since the Staff has included the total amount paid by the Company in the on-going cost of service, it recommends that any and all reductions in this level resulting from a successful appeal, be returned to ratepayers in a future rate proceeding.

Staff Expert/Witness: Lisa M. Ferguson

8. Uncollectible Expense

Uncollectible expense is the portion of retail revenues that Ameren Missouri is unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. Through the third party collection agency, Ameren Missouri is subsequently successful in collecting some portion of the delinquent amounts owed. The Staff examined the actual fourteen-year history of billed revenues that were never collected (net write-offs) from October 1997 through October 2010 and has included in the cost of service calculation a three-year average (twelve months ending October 2007, 2009, and 2010) of adjusted electric net write-offs for uncollectible expense.

Staff Expert/Witness: Kofi Agyenim Boateng

9. Advertising Expense

In forming its recommendation of the allowable level of Ameren Missouri's advertising expense, the Staff relied on the principles it has consistently applied adhering to the Commission's decision in *Re: Kansas City Power and Light Company*, Case Nos. EO-85-185, et al., 28 Mo.P.S.C. (N.S.) 228, 269-71 (1986). In that case, the Commission adopted an approach that classifies advertisements into five categories and provides rate treatment of recovery or disallowance based upon a specific rationale. The five categories of advertisements recognized by the Commission are as follows:

1. General: informational advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the company's public image;
5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements explaining that a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement (Report and Order in KCPL Case Nos. EO-85-185, et al., 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)).

Accordingly, in the current rate case, the Staff has proposed an adjustment to exclude the costs of institutional, political, and promotional advertising from recovery in rates. Costs for safety advertising and general advertising directed towards the benefit of existing customers were not adjusted by the Staff. In addition, Staff has requested to review any advertising related items that have been allocated from the Corporate level. As of this direct filing, Staff has not had the ability to fully review these items. Staff will not propose an adjustment for direct filing but this item may be subject to future adjustment during true-up.

Staff Expert/Witness: Lisa M. Ferguson

10. Franchise Taxes

See the discussion in Section VIII. A. 4. b., Adjustment to Remove Gross Receipts Tax

Staff Expert/Witness: Kofi Agyenim Boateng

11. Test Year Storm Cost

The Staff proposes to include approximately a $2.9 million normalized test year level for non-labor related storm restoration costs based on a 45 month average for all storm costs incurred between April 1, 2007 and December 31, 2010. The April 1, 2007 starting point of the Staff's average represents the first day of the test year established as part Case No. ER-2008-0318 and extends through the most current information available as part of the Company's current rate proceeding. Therefore, the time period covered by the Staff's 45 month normalized level excludes all storm costs that occurred between July 1, 2006 and December 31, 2006. This is consistent with the Commission's ruling as part of its Report and Order in Case No. ER-2007-0002 where the Commission stated:

> The Commission concludes that AmerenUEs 2006 storm related operating and maintenance shall be offset against its 2006 SO2 allowance sales revenue. Thereafter, the company's 2006 storm related operating and maintenance shall be offset against its 2006 SO2 allowance sales revenue. Thereafter, the Company's 2006 storm related operation and maintenance costs shall not be considered in any manner in any future rate proceeding.

The Staff's 45 month average also excludes storm costs related to the January 2007 ice storm which is currently being recovered by the Company through a Commission approved AAO amortization established as part of Case Nos. EU-2008-0141 and ER-2008-0318.

As part of the April 1, 2007 through December 31, 2010 time period covered by Staff's normalization, the Staff excluded from the determination of its normalized level, all costs related to two storm amortizations that the Company is currently already recovering in rates. These two storm amortizations currently provide the Company recovery for extraordinary storms costs which occurred during the time period covered by the Staff's 45 month average as approved by this Commission as part of Case Nos. ER-2008-0318 and ER-2010-0036. Removing all costs associated with these amortizations that the Company is already recovering in rates, from the overall balance of non-labor storm costs that Staff has used in developing its normalized level is necessary in order to prevent any double recovery of these costs from occurring. The Staff will continue to evaluate storm restoration costs through the end of the February 28, 2011, true-up cutoff date established by the Commission in this rate proceeding, in order to determine whether any further adjustment to the cost of service are necessary.

In the next section of this Cost of Service Report, the Staff will describe in detail all storm cost amortizations the Company is already recovering as part of current rates and Staff's recommendation that each of these amortizations be continued as part of the Commission's determination of rates in the current proceeding.

Staff Expert/Witness: John P. Cassidy

12. Storm Cost Amortization Expense

a. Storm Cost from ER-2007-0002

As part of the Stipulation and Agreement that was approved by the Commission in Case No. ER-2007-0002, Ameren Missouri's cost of service was reduced by $4,442,000 for storm costs and the Company was allowed to recover an amortization of approximately $800,000 annually from July 1, 2007 through June 30, 2012. During the test year ending March 31, 2010, the Company recorded a full twelve months of the annual amortization of $800,000. Therefore, no adjustment is necessary to annualize the storm amortization that was established by the Commission as part of Case No. ER-2007-0002. The Staff recommends that the Company continue to recover $800,000 as part of the determination of rates in the current case.

b. Storm Cost from ER-2008-0318

As part of an agreement reached in Case No. ER-2008-0318, Ameren Missouri's cost of service was reduced by $4,856,527 for extraordinary storm costs that had occurred during the test year that was established as part of that rate proceeding and the Company was allowed to recover an amortization of $971,400 annually from March 1, 2009 through February 28, 2014. As part of the current rate proceeding, during the test year ending March 31, 2010, the Company recorded a full twelve months of the annual amortization of $971,400. Therefore, no adjustment is necessary to annualize this storm amortization that was established as part of Case No. ER-2008-0318. The Staff recommends that the Company continue to recover $971,400 as part of the determination of rates in the current rate proceeding.

c. Storm Cost from ER-2010-0036

As part of the Company's last rate proceeding, ER-2010-0036, the Company recorded approximately $10.4 million of O&M, non-labor related storm restoration costs during the March 31, 2009 test year that was established by the Commission as part of that case. The Staff proposed to include a four year average of O&M, non-labor related storm restoration costs, or $6.4 million as a normal ongoing level. The Staff also proposed to allow recovery for the approximate $4.0 million difference, which represented extraordinary storm costs, through an amortization over five years. The Company proposed that it be allowed to recover the $10.4 million test year level as a base level in rates and also requested that the Commission establish a tracking mechanism to track actual expenses against this base level. As part of the Report and Order in that case, the Commission on pages 68-69 stated the following: "AmerenUE's request to establish a tracking mechanism is denied. AmerenUE shall include $6.4 million in its cost of service for storm restoration costs. The remaining $4 million in test year storm restoration expense shall be amortized and recovered over five years."

Since approved rates in the last case were not effective until June 21, 2010, no amount of this amortization was recorded on the Company's books during the test year ending March 31, 2010, that was established by the Commission as part of the current rate proceeding. Therefore, the Staff included approximately an $800,000 adjustment to increase expense that was included in the cost of service calculation in this case in order to reflect a full year of storm cost amortization as approved by the Commission in File No. ER-2010-0036.

d. Storm Cost Accounting Authority Order (AAO) Case Nos. EU-2008-0141 and ER-2008-0318

As a result of Case No. EU-2008-0141, the Commission granted Ameren Missouri an AAO to defer the costs related to the ice storm that occurred on January 13, 2007. As part of Case No. ER-2008-0318, the Commission ruled that the appropriate starting point for the amortization period for the storm costs that were deferred through the AAO should begin in March 2009 and end in February 2014. During the test year ending March 31, 2010, the Company recorded a full twelve months of annual amortization of $4.9 million. Therefore, no adjustment is necessary to annualize this storm amortization that was established as part of Case Nos. EU-2008-0141 and ER-2008-0318. The Staff recommends that the

Company continue to recover $971,400 as part of the determination of rates in the current rate proceeding.

Staff Expert/Witness: John P. Cassidy

13. Callaway Refueling Adjustment

Since the Company refuels the Callaway nuclear power plant on an eighteen-month cycle, the cost of refueling must be normalized to reflect the amount incurred during a twelve-month period. Staff's 12 months ending March 31, 2010 test year does not include any of these refueling costs, since the Company last refueled Callaway during the months of April through June of 2010. Staff's normalization adjustment adds $19 million, which is two thirds of the approximately $28.5 million of Callaway refueling non-labor maintenance project costs. All labor related costs associated with the Callaway refueling are addressed in Staff's payroll adjustments as discussed by Staff witness John P. Cassidy.

Staff Expert/Witness: Lisa K. Hanneken

14. Training Cost

a. Production Training

In Case No. ER-2008-0318 the Commission added $1,410,000 to Ameren Missouri's cost of service to fund increased production operations training staff. The Commission also added $360,000 to Ameren Missouri's cost of service, which reflected a five-year amortization of $1,800,000, to fund training equipment and materials, and external costs, due to increased training staff. Since Ameren Missouri began staffing these permanent training positions and incurring other related costs in April 2009, the start-up of these programs is included in the 12 months ending March 31, 2010 test year for File No. ER-2011-0028. The payroll and benefits costs related to permanent production training employees are encompassed in the Staff's adjustments for wage rates and employee levels as discussed in this report by Staff witness John P. Cassidy. For the non-permanent employee costs the Staff has identified an on-going level and is proposing a five-year amortization of the amount that exceeds the ongoing level. Staff is also proposing a five–year amortization of the cost incurred during the test year for training equipment and materials, and external costs, due to increased training staff, including production operations training staff. As a result of including capital cost in the five-year amortization prescribed by the Commission, Staff has removed this cost from plant in service and the calculation of depreciation expense.

Staff Expert/Witness: Stephen M. Rackers

b. Distribution Training

In File No. ER-2010-0036 the Commission added $1,290,000 to Ameren Missouri's cost of service to fund increased distribution training staff. The Commission also added $420,000 to Ameren Missouri's cost of service, which reflected a five-year amortization of $2,100,000, to fund training equipment and materials, and external costs, due to increased training staff. Since Ameren Missouri did not begin staffing these positions and incurring other related costs until August 2010, none of the cost of these programs is included in the 12 months ending March 31, 2010 test year for File No. ER-2011-0028. The payroll and benefits costs related to permanent distribution training employees are encompassed in the Staff's adjustments for wage rates and employee levels as discussed in this report by Staff witness John P. Cassidy. For the cost incurred for training equipment and materials, and external costs, due to increased distribution training staff the Staff has included a five year amortization of the amounts incurred through November 30, 2010. Staff intends to include in its five year amortization any additional cost Ameren Missouri incurs for training equipment and materials and external costs due to increased distribution training staff through the February 28, 2011 true-up cut-off date. As a result of including capital cost in the five-year amortization prescribed by the Commission, Staff has removed this cost from plant in service and the calculation of depreciation expense.

Staff Expert/Witness: Stephen M. Rackers

15. Rebranding Costs

The Company incurred costs from two outside consultants in part due to its recent decision to change its trade name from AmerenUE to Ameren Missouri that is part of an overall strategy to "rebrand" Ameren and its subsidiaries. The Staff adjusted its cost of service calculation for Ameren Missouri to remove all rebranding costs that Ameren Missouri incurred for outside consultants related to the rebranding during the test year ending March 31, 2010. The Staff's adjustment to remove all of these rebranding costs is consistent with the Company's proposed treatment. The Staff will continue to examine this issue as part of its true-up audit through February 28, 2011. Based upon this true-up examination the Staff may make additional adjustments to the cost of service as necessary.

Staff Expert/Witness: John P. Cassidy

16. Power Plant Maintenance Expense

Staff is recommending a normalization of the non-labor maintenance expense for Ameren Missouri's steam power plants in order to address the fluctuations in annual expense levels that have occurred in connection with maintenance projects at the four plants (Meramec, Sioux, Labadie and Rush Island). Therefore, Staff utilized a three-year average ending March 31, 2010, for the non-labor coal power plant maintenance. The following chart summarizes the actual non-labor maintenance costs that were experienced at each steam plant during the past three years including the test year:

		12-mos ending	
Plant	**3/31/2008**	**3/31/2009**	**3/31/2010**
Meramec	$8,461,000	$12,728,000	$13,394,000
Sioux	$10,884,000	$23,581,000	$14,865,000
Labadie	$16,601,000	$30,667,000	$16,406,000
Rush Island	$15,143,000	$8,409,000	$13,185,000

Based upon this three year average, Staff has reflected an additional $7,064,000 of non-labor steam power plant maintenance in the cost of service calculation. Additionally, Staff has included an additional adjustment in order to include estimated ongoing non-labor maintenance expense for the Sioux plant's new scrubbers which were placed into service in late 2010. Since the scrubbers were not operational at the time of the Company's filing, an estimated $500,000 of annual expense was included in Ameren Missouri's cost of service calculation. However, since that time the Company has provided Staff with a revised estimate of $300,000. Given that there is little or no maintenance history for these facilities, Staff is including the revised estimate of $300,000 in its cost of service, but will review all actual data regarding the maintenance of the scrubbers as part of its true-up analysis.

Staff also reviewed the Company's non-labor maintenance expense for its Osage and Keokuk hydro plants. The level of non-labor maintenance expense that was experienced during the test year at the Osage plant was negative due to accounting adjustments that were recorded by the Company that addressed events that had occurred in prior years. The non-labor maintenance expense at Keokuk was abnormally high, which was also due to accounting adjustments for events which occurred in prior years. Staff is recommending a five-year average of expenses for each of these hydro plants in order to reflect a normal on-going expense level in the cost of service calculation. The following chart summarizes the actual non-labor maintenance expense experienced at each of these hydro plants during the last five years including the test year:

	12-mos ending				
Plant	**3/31/2006**	**3/31/2007**	**3/31/2008**	**3/31/2009**	**3/31/2010**
Osage	$615,715	$542,744	$2,449,866	$4,323,181	$(1,720,323)
Keokuk	$523,998	$386,677	$438,169	$773,673	$2,777,253

Based on its five-year averages, Staff increased the cost of service calculation by $2,962,560 to reflect a $1,242,237 normalized non-labor maintenance for the Osage plant but reduced the cost of service by ($1,797,299) to reflect a $979,954 normalized level for the Keokuk plant.

Staff's historical analysis of non-labor maintenance costs associated with the Company's Taum Sauk pumped storage facility was limited due to the fact that its rebuild was not completed until April 2010. Therefore, only a limited amount of useable data is available for this plant. In addition to this limitation, in August 2010, an abnormally high monthly amount of $5.6 million was recorded to write off the deductible related to the Taum Sauk failure. Therefore, Staff is recommending an annualized average of the monthly amounts for April – October 2010, excluding August, which results in an on-going annual expense level of $543,422. As part of its true-up audit Staff will review actual costs through February 28, 2008 in order to determine if any further adjustments to the cost of service are necessary. Additionally, Staff removed $350,700 from the test year expense level of account 539 in order to normalize the Company's operations expense for the Taum Sauk plant.

In addition to the above items, Staff has made an adjustment of $1,056,000 to reduce the cost of service calculation in order to remove prior period adjustments recorded by the Company in account 512 during the test year related to costs associated with prior period asbestos abatement at Ameren Missouri's facilities.

Staff Expert/Witness: Lisa K. Hanneken

17. Injuries & Damages

Staff reviewed the accruals, payments, and reserve balances for the Company's provision of injuries and damages expense. Rather than an accrual, the Staff recommends that the actual payments be used in the determination of revenue requirement. Therefore, the Staff performed an analysis of the 12- month periods ending in October for the years 2004-2010. Staff's analysis of this data revealed an overall decreasing trend in payments, net of insurance settlements. As a result of its analysis, Staff recommends utilizing the 12- months ending October 2010 as the ongoing expense level.

Staff Expert/Witness: Lisa M. Ferguson

18. PSC Assessment

On an annual basis, the Company is assessed a fee from the Commission based upon its revenues from the previous calendar year. This assessment is issued to the Company in July of each year and payable either as one sum or in quarterly installments due in July, October, January, and April. In July of 2010 the Company was assessed $4,034,127 for the fiscal year ending June 30, 2011. Staff has included this most recent assessment amount as the ongoing annual expense level to include in the cost of service.

Staff Expert/Witness: Lisa M. Ferguson

19. Corporate Franchise Tax

Franchise tax is a tax that corporations pay in advance for doing business within the state. Franchise tax must be paid if the corporation's assets (in or apportioned to Missouri) exceed one million dollars for franchise taxable years beginning on or after January 1, 2000, or ten million dollars for franchise taxable periods beginning on or after January 1, 2010. The

Staff used the actual taxes paid during the test year as the basis for its determination of the on-going expense level.

Staff Expert/Witness: Lisa M. Ferguson

20. Miscellaneous Expenses

During the test year the Company had numerous miscellaneous costs booked to its General and Administrative accounts. After reviewing these expenses Staff has removed a total of $456,813 from the Company's test year costs, which provide no ratepayer benefit. These charges include items such as donations, sponsorships of community events, sponsorship of sporting events among other similar items.

Staff Expert/Witness: Lisa M. Ferguson

21. Short-term Credit Facility Fees

In Ameren Missouri's most recent rate proceeding, File No. ER-2010-0036, short-term credit facility fees appropriately allocated to Ameren Missouri were allowed to be booked to a regulatory asset and amortized over two years into accumulated funds used during construction (AFUDC), which were capitalized as a cost of plant. That facility agreement has expired and was recently replaced by a new agreement. In File No. ER-2010-0036, the Staff's position was that these fees should be treated as a cost of short-term debt. Since short-term debt is often used to support construction work in progress (CWIP), these fees were capitalized. Generally, because it is assumed that short-term debt supports CWIP, the corresponding amount of short-term debt is not included in the capital structure used in the determination of revenue requirement. In this case, the Staff continues to assert the position that short-term credit facility fees should be treated as a cost of short-term debt. Therefore, if all or part of short-term debt is used to support construction cost, the related fees should be capitalized. However, if short-term debt is used, in whole or in part, to support non-construction activities, then the fees, or some portion of the fees, should be expensed. In this case, Staff witness David Murray does not include any short-term debt in the capital structure used to determine revenue requirement for purposes of Staff's direct case. Consequently, Staff has not included any portion of the fees in expense. Therefore, the Staff recommends that the fees for the new credit facility be amortized to CWIP over the term of the credit facility, three years. The Staff will continue to perform additional analysis and review of information related to the use of short-term debt as part of its true-up audit and as a result may adjust its treatment of short-term credit facility fees.

Staff Expert/Witness: Stephen M. Rackers

22. Taum Sauk Reservoir Failure

Ameren Missouri has agreed to hold ratepayers harmless for costs associated with the Taum Sauk reservoir failure and all related clean-up activities. Therefore, Staff has eliminated from the cost of service calculation approximately $2.2 million of expense that was incurred by the Company during the test year that related to the reservoir failure and related clean-up activities. However, as a result of information discussed during a meeting with the Company, on December 7, 2010, Staff is concerned that some costs incurred by the Company in connection with the reservoir failure and related clean-up activities may have been included in plant balances through March 31, 2010. On January 13, 2011, Staff submitted Staff Data Request No. 374 to the Company seeking specific information regarding any and all capitalized amounts which related to the Taum Sauk reservoir failure that Company may have recorded in its March 31, 2010 plant balances. However, the Company objected to Staff's data request on January 24, 2011 stating that Staff's data request, was among other reasons, neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. The Company went on to say in its objection letter that, "…it should be noted that the revenue requirement in this case includes only capital costs associated with construction of the new upper reservoir (what this DR refers to as the 'rebuild')." Due to the Kansas City Power & Light Company rate case hearings in File No. ER-2010-0355, Staff counsel have not had an opportunity to address Ameren Missouri's objection but Staff counsel intend to do so with the hope of obtaining the necessary information that Staff is seeking.

Staff plans to review this or any other information once it is made available by the Company, in order to determine whether any further adjustments to the cost of service are necessary to address any capitalized amounts related to the Taum Sauk reservoir failure.

Staff Expert/Witness: Lisa K. Hanneken

G. Depreciation Expense

1. Venice Depreciation Review

a. Scope

Depreciation Engineers in the Engineering and Management Services Department, Utility Services Division, have reviewed Ameren Missouri's rate request as it relates to depreciation. The Ameren Missouri Venice Power Station (Venice) in the state of Illinois was partially closed and partially retired in 2002. Ameren Missouri has not presented evidence that it has released any of the operational permits for the site, and Ameren Missouri continues to maintain the Illinois Air Quality permit for Venice site. The Company also continues to generate substantial amounts of electricity from the power site. During this period of time from 2002 until the present case, the Company continues to book retirements and additions at this location.

b. Issue

Ameren Missouri's filing includes a request for a special amortization for unrecovered retirement costs associated with the retired steam Venice Power Station. During the period this facility was in operation, depreciation was accrued for this and all other Ameren Missouri steam power plants in Ameren Missouri's steam production generation fleet. The fleet's deprecation was accounted for using mass asset accounting, thus the ordered depreciation rates did not prescribe depreciation for each power plant, and were prescribed for the fleet of all steam power plants. Ameren Missouri now contends that since the power plant was retired no additional depreciation accruals have been made that would pay for the recently incurred retirement costs at the Venice. Ameren Missouri accrued depreciation expense reserves for Venice while Venice was in operation which was placed into the steam production fleet's mass asset depreciation reserve. The depreciation reserves for the steam production accounts are over accrued and contain several hundred million dollars in reserves for these costs. In File No. ER-2010-0036, Staff recommended that Ameren Missouri use these reserves to pay for any retirement costs associated with the Venice or any other steam power station. This is the basis and these are the accounts for which the depreciation reserves were accrued. These depreciation reserves have been accumulating from the inception of regulatory depreciation. The Commission has never ordered depreciation rates specific to the Venice.

c. Recommendation

Until File No. ER-2010-0036, when the Commission adopted the life span treatment of depreciation for the steam (coal) plants the reserves, including any components for net salvage, were simply accumulated to accounts 311 Structure & Improvements, 312 Boiler Plant Equipment, 314 Turbo Generator Equipment, 315 Accessory Electric Equipment, 316 Miscellaneous Power Equipment with no distinction regarding a particular power plant. The Commission ordered depreciation rates by account, not location. The funds are available for any retirements from these accounts for any steam plant assets. The lack of funds in the Venice-specific reserve account is only the result of dividing the reserves into site-specific accounts without assigning any to Venice. Ameren Missouri has allocated out all of the steam generation fleet's depreciation reserves without allocating any depreciation reserves to the Venice steam production accounts. The existing depreciation reserves include dollars that were accrued on the Venice investment. Staff recommends that Ameren Missouri be ordered to allocate dollars from the remainder of the steam generation fleet's reserves to cover any costs associated with the Venice retirements.

Staff Expert/Witness: Guy C. Gilbert, MS, PE, PG

2. Capitalized Depreciation and O&M

Staff made an adjustment to remove a portion of the annualized depreciation expense calculated on transportation and power operated equipment. This equipment is used by the Company to perform both maintenance and construction activities. A portion of the depreciation calculated on this equipment is capitalized and charged to construction projects. Therefore, depreciation must be removed from the annualized depreciation expense included in the calculation of net operating income in order to prevent a double recovery. In addition, the Staff reduced the cost of service calculation in order to annualize O&M related depreciation.

Staff Expert/Witness: Lisa M. Ferguson

H. Income Tax

Income tax expense calculated by the Staff is largely consistent with the methodology used in Ameren Missouri's most recent rate cases, Case Nos. ER-2007-0002, ER-2008-0318 and ER-2010-0036 with three notable exceptions. The first change from these previous cases that the Staff has reflected in the income tax expense included in the cost of service calculation for Ameren Missouri in the current case, deals with a tax deduction that was reflected on Ameren Corporation's (the parent of Ameren Missouri) tax return for the Employee Stock Option Plan (ESOP). The Staff contends that Ameren Missouri should receive a representative portion of this deduction because this tax deduction is driven in part by the Ameren Missouri employees that participate in the ESOP and has adjusted the level of income tax expense to reflect this deduction. The second change in the calculation of income tax expense from previous rate cases, results from the Staff's inclusion of a deduction in the determination of income tax expense for dividends that were paid on certain shares of preferred stock that was issued by Union Electric Company prior to October 1, 1942, and is included in the capital structure in this case. Lastly, the Staff has excluded all city taxes as part of the calculation of current income tax expense that was included in its cost of service calculation because the Company has not paid city taxes in the past few years and has indicated to the Staff that it does not expect to pay any city taxes during 2011.

Staff Expert/Witness: John P. Cassidy

IX. Fuel Adjustment Clause (FAC)

Staff makes the following recommendations to the Commission regarding Ameren Missouri's Fuel Adjustment Clause (FAC):

1. To reduce customer confusion Ameren Missouri should stop using the acronym FAC on its customers' bills and, instead, use the words "Fuel and Purchased Power Adjustment."

2. The length of the FAC recovery periods be changed from twelve months to eight months.

3. The sharing mechanism from be changed from 95% returned/recovered from the customers and 5% kept/absorbed by Ameren Missouri to 85% returned/recovered from the customers and 15% kept/absorbed by Ameren Missouri.

4. Net Base Fuel Cost ("NBFC") be re-based to the fuel and purchased power cost net of off-system sales ("OSS") that are included in the permanent rates in this case.

5. The normalized, annualized kilowatt-hour ("kWh") usage at the Ameren Missouri Midwest Independent Transmission System Operator ("MISO") load node be used to calculate the NBFC rate and the kWh at the Ameren Missouri MISO load node be used as accumulation and recovery period kWh sales.

6. Retain the current language in the FAC tariff sheet definition of OSSR that requires the revenues from sales to municipal utilities not be included in OSSR.

7. Ameren Missouri be ordered to provide a list of additional filing requirements that will aid the Staff in performing FAC tariff, prudence and true-up reviews.

In its Class Cost-of-Service Report to be filed on February 10, 2011, Staff will propose changes to Ameren Missouri's FAC tariff sheets to clarify terms and the timings of true-up filings. Staff will also propose in that report, changes to Ameren Missouri's FAC tariff sheets designed to make the methods used to calculate the base fuel cost and actual fuel cost in each accumulation period more consistent.

Staff Expert/Witness: Lena M. Mantle

A. History

In 2005, Senate Bill 179 became law codified at § 386.266, RSMo Supp. 2010. Among other things Senate Bill 179 empowered the Commission to approve, modify, or reject in a general electric rate case a FAC embodied in tariff sheets that would permit, between general rate cases, adjustments to customer rates based on changes to the utility's fuel and purchased power costs. The Commission promulgated rules 4 CSR 240-20.090 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms, and 4 CSR 240-3.161 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements (FAC rules) to implement this aspect of Senate Bill 179. These rules became effective June 30, 2007.

Ameren Missouri, then doing business as AmerenUE, first requested the Commission to approve a FAC when it filed a general electric rate increase case, Case No. ER-2007-0002, on July 3, 2006—prior to the finalization of the FAC rules. In the Commission's May 22, 2007 *Report and Order*, the Commission concluded:

> After carefully considering the evidence and arguments of the parties, and balancing the interests of ratepayers and shareholders, the Commission concludes that AmerenUE's fuel and purchased power costs are not

> volatile enough justify the implementation of a fuel adjustment clause at this time**.**

Ameren Missouri filed another general electric rate increase case, on April 4, 2008, Case No. ER-2008-0318. In the Commission's February 2009 *Report and Order* in that case the Commission authorized Ameren Missouri to implement a FAC. On February 19, 2009 the Commission approved FAC tariff sheets that took effect on March 1, 2009.

On the heels of Case No. ER-2008-0318, on July 24, 2009, less than 5 months after its original FAC tariff sheets became effective, Ameren Missouri, still then doing business as AmerenUE, filed another general electric rate increase, File No. ER-2010-0036. In that case, on February 17, 2010, the Commission issued an order titled, *Order Directing the Parties to Submit Testimony Concerning the Appropriateness of AmerenUE's Current Fuel Adjustment Clause.* In this order the Commission requested:

> The Commission would like the parties in their testimony to review AmerenUE's current fuel adjustment clause and advise the Commission whether the current 95 percent pass through mechanism: 1) affords AmerenUE a sufficient opportunity to earn its authorized return on equity, and/or 2) provides AmerenUE with a sufficient financial incentive to be prudent in and take reasonable efforts to minimize its fuel and purchased power costs?

In Staff witness Lena M. Mantle's supplemental direct testimony admitted in evidence in that case, she gave the following reason for why Staff had not recommended changes to Ameren Missouri's sharing mechanism:

> [S]ince little time had passed after AmerenUE's FAC was implemented, Staff did not have enough 'data' to meaningfully analyze the effectiveness of AmerenUE's FAC in delivering the purported benefits AmerenUE asserted a FAC would provide. Given that the Commission had just authorized AmerenUE to implement a FAC, Staff chose to proceed cautiously.

In its Report and Order in this case—Case No. ER-2010-318—the Commission concluded:

> AmerenUE should be allowed to continue to implement the fuel adjustment clause the Commission approved in the company's last rate case. Given the short amount of time AmerenUE's fuel adjustment clause has operated and the resulting lack of information about how effective the current sharing mechanism has been, the Commission will not modify that clause, except as provided in the previously approved stipulation and

> agreement. The Commission expects to further review AmerenUE's fuel adjustment clause and the appropriate sharing mechanism to be included in that clause as part of AmerenUE's next rate case.

Revised FAC tariff sheets became effective in this case, Case No. ER-2010-0036, on June 23, 2010.

On August 31, 2010, Staff filed in File No. EO-2010-0255 the results of its prudence audit of Ameren Missouri's accumulation periods 1 and 2 (March 1, 2009 through September 30, 2009). In its report, Staff alleged that Ameren Missouri was imprudent when it did not include the revenues from two contract sales of energy in determining the associated FAC charges that are billed to its customers. This case is a contested case currently open before the Commission and briefs are scheduled to be filed soon after this report is filed.

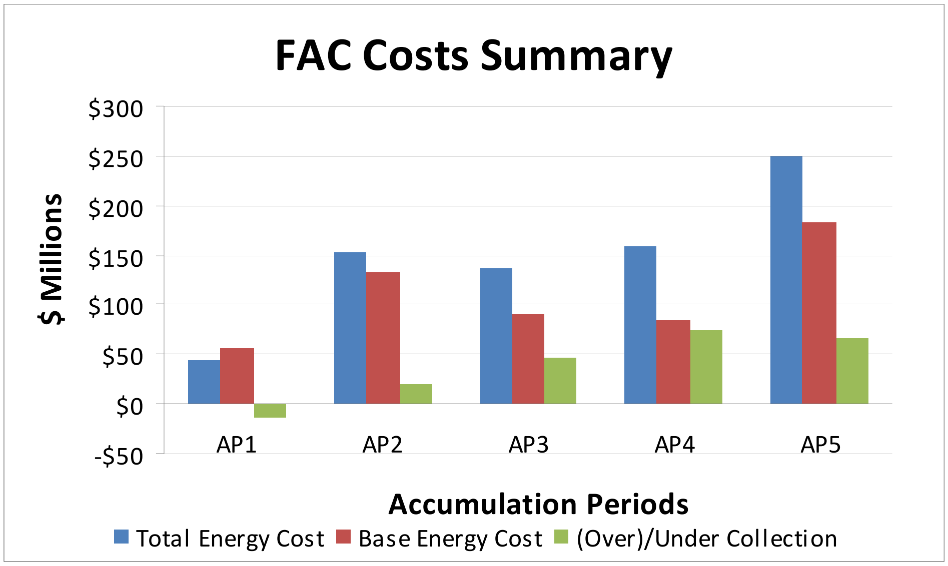
On December 1, 2010, Ameren Missouri initiated File No. ER-2010-0274 seeking to true-up its first recovery period. As a part of this true-up filing, Ameren Missouri has asserted that the NBFC rate in the tariff that originally established the Company's FAC was calculated incorrectly and that as a result the Company is entitled to the additional revenue that would have been collected had the NBFC rate been correctly calculated. Staff opposes including these additional revenues. This case is a contested case that is currently open before the Commission. A proposed procedural schedule was filed in the case on February 4, 2011.

Attached to this report as Appendix 3, Schedule LMM-1 is a timeline of certain events that have occurred since the Commission first approved a FAC for Ameren Missouri through the time of this filing.

Staff Expert/Witness: Lena M. Mantle

B. Summary of Ameren Missouri's Fuel and Purchased Power Costs Net Off-System Sales TOC2

The graph below shows for each accumulation period since Ameren Missouri was granted a FAC, a summary of Ameren Missouri's actual fuel and purchased power costs net OSS (total energy costs), base fuel and purchased power costs net of OSS (base energy costs), and the over/under collection of fuel costs through the permanent rates.

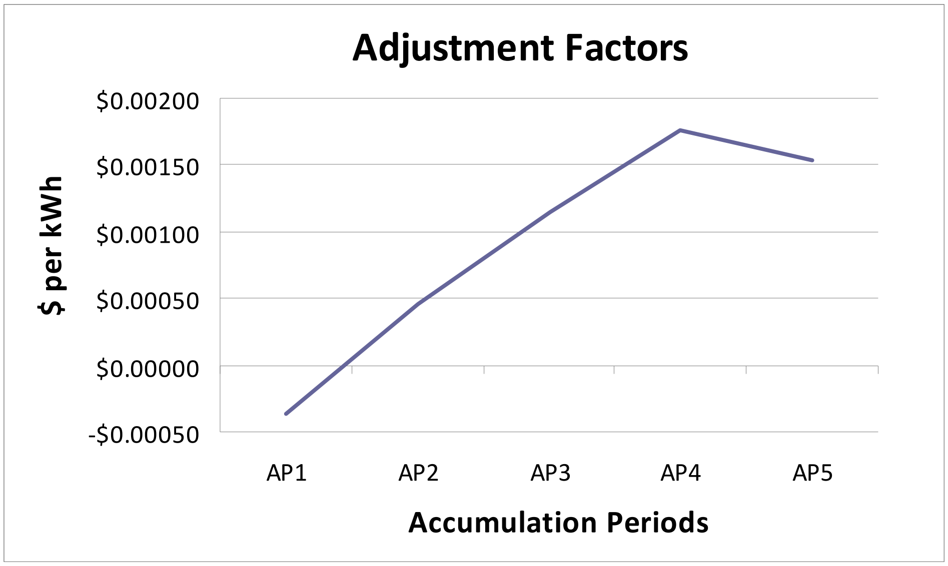


In Ameren Missouri's FAC there are different base energy costs per kWh for the summer months of June through September than for the non-summer months. Accumulation periods 2 and 5 ("AP2" and "AP5," respectively) were summer accumulation periods. At the conclusion of its general electric rate case, File No. ER-2010-0036, during AP5 the base energy costs in Ameren Missouri's FAC were re-set. AP1, AP3 and AP4 were non-summer months. Base energy cost per kWh usage was constant across all the non-summer periods. In the first accumulation period, which was only three months in duration, Ameren Missouri's actual total energy costs were less than the base energy costs for that period which resulted in Ameren Missouri over collecting its fuel costs in its permanent rates. In each of its other accumulation periods, Ameren Missouri's actual total energy costs exceeded the base energy costs for the period which resulted in Ameren Missouri under-collecting its fuel costs in its permanent rates.

This bar graph also shows an increase in Ameren Missouri's actual total energy costs from just less than $50 million for AP1, to approximately $250 million for AP5. Since AP1 is only the three non-summer months of March 2009 through May 2009) and AP5 is the four months of the summer of 2010, it is more meaningful to compare Ameren Missouri's actual total energy costs for AP2 (June 2009 through September 2009) of a little over $150 million to its actual total energy costs for AP5 (June 2010 through September 2010) of approximately $250 million. According to information from the monthly reports Ameren Missouri supplied to Staff for AP2 and AP5, its retail usage increased by 15% and its actual total energy costs increased by 64%. The 15% increase in retail usage should not be interpreted as growth.

While some of the increase may due to growth, it is more likely the increase is due to differences in the weather - the mild summer of 2009 and the hot summer of 2010. The 64% increase in Ameren Missouri's actual total energy costs during this timeframe is attributable to a 30% increase in Ameren Missouri costs to serve retail load and a 17% decrease in its OSS revenues.

The graph below shows the actual Ameren Missouri FAC adjustment factors for these five accumulation periods.



This graph shows that over time the adjustment factors consistently increased until AP5. It is not unexpected that the fuel and purchased power adjustment (FPA) for AP5 is lower than that for AP4, since NBFC was re-based during AP5. It is likely that due to re-basing NBFC during AP5 the FPA for AP5 would have been even lower (closer to zero) if the weather during the summer of 2010 was "normal"; however, since the summer of 2010 (AP 5) was hotter than normal and marginal fuel cost is higher than average fuel cost, it is reasonable that the FPA for AP5 is greater than zero.

Staff Expert/Witness: Lena M. Mantle

C. <u>Sharing Mechanism</u>

The Commission stated in its *Report and Order* in Ameren Missouri's last rate case, File No. ER-2010-0036, that as part of Ameren Missouri's next rate case it expected to further review

Ameren Missouri's FAC and the appropriate sharing mechanism to be included in that clause. In reviewing the sharing mechanism, Staff took into consideration the following:

1) Ameren Missouri's request in this case to rebase its FAC NBFC;

2) Ameren Missouri's request for additional revenue in its true-up filing for AP1 based on an assertion that the FAC NBFC established in the 2008 rate case are too high;

3) The results of Staff's prudence audit that included AP1 and AP2 where Staff concluded Ameren Missouri was imprudent for excluding from its FPA calculations costs and revenues associated with its contract sales of energy to American Electric Power Operating Companies (AEP) and to Wabash Valley Power Association, Inc. (Wabash);

4) Information Ameren Missouri provided in its monthly FAC filings and in its filings to change its FPA information including its fuel and purchased power costs, and OSS revenues; and

5) The impact on Ameren Missouri's net income of changing the sharing percentage in its FAC sharing mechanism.

Because Ameren Missouri has two open contested cases before the Commission regarding its FAC, and the information Ameren Missouri has provided in its monthly FAC submissions show that Ameren Missouri's total energy costs have increased greatly at the same time its OSS have decreased greatly, Staff recommends the Commission modify the sharing mechanism of Ameren Missouri's FAC from 95%/5% sharing to 85%/15% sharing. With this modification Ameren Missouri's retail customers would pay 85% of any increase in fuel and purchased power costs above the base fuel and purchased power costs included in permanent rates (Net Base Fuel Cost) and receive 85% of any decrease. At the same time Ameren Missouri would absorb 15% of any increase in fuel and purchased power costs above the base fuel and purchased power costs included in permanent rates and keep 15% of any decrease. In the paragraphs following Staff addresses each of the five above considerations in detail.

In Missouri, there are three investor-owned electric utilities that have FACs—Ameren Missouri, KCP&L Greater Missouri Operations Company (GMO) and The Empire District Electric Company (Empire). All three have now requested two general electric rate increases since the Commission first approved their FAC. Ameren Missouri is the only one of the three to request its FAC NBFC be rebased as a part of its rate increase requests. Neither GMO nor Empire has requested to rebase its FAC NBFC in their general electric rate cases. If a utility with a FAC does not propose to rebase its Net Base Fuel Costs in its rate cases, then the sharing mechanism for that utility is not set correctly. The purpose of a FAC is to pass through the differences between fuel and purchased power costs included in rates set in general rate cases and the costs the fuel and purchased power costs the utility actually incurs. Therefore, the sharing mechanism should give the utility an incentive to rebase Net Base Fuel Costs, i.e., the portion of the fuel cost that the utility is absorbing or keeping should be great enough that the utility wants to rebase. Ameren Missouri has consistently included rebasing its Net Base Fuel Cost as part of its general electric rate increase cases. Therefore this is not why Staff is proposing to change the 95%/5% sharing mechanism of Ameren Missouri's FAC.

Staff completed its first prudence audit associated with Ameren Missouri's FAC and filed its report on August 31, 2010 in File No. EO-2010-0255. In its report, Staff stated its conclusion that Ameren Missouri was imprudent for not flowing through the Off System Sales Revenue (OSSR) component of its FAC all the costs and revenues associated with its contract sales of energy to American Electric Power Operating Companies (AEP) and to Wabash Valley Power Association, Inc. (Wabash) during the period of March 1 to September 30, 2009. If these revenues and costs are flowed through the OSSR component they are included in the FPA which in turn is used to determine retail customers FAC charges. The Commission held a hearing regarding this alleged imprudence on January 10-11, 2011. Briefs and reply briefs will soon be filed in the case. Staff, Ameren Missouri and others had discussions in Ameren Missouri's last rate case, File no. ER-2010-0036, regarding the tariff language of Ameren Missouri's FAC and whether or not these contract revenues should be flowed through the OSSR component of Ameren Missouri's FAC, and thereby be included in determining the FPA used to determine customer FAC charges. To clarify how similar contract sales would be treated in the future, in File No. ER-2010-0036, the parties agreed to, and the Commission ordered, a change to Ameren Missouri's FAC tariff language regarding OSS revenue. At this time Staff is unaware of any other contracts for which Ameren Missouri is not flowing costs and revenues through its FAC.

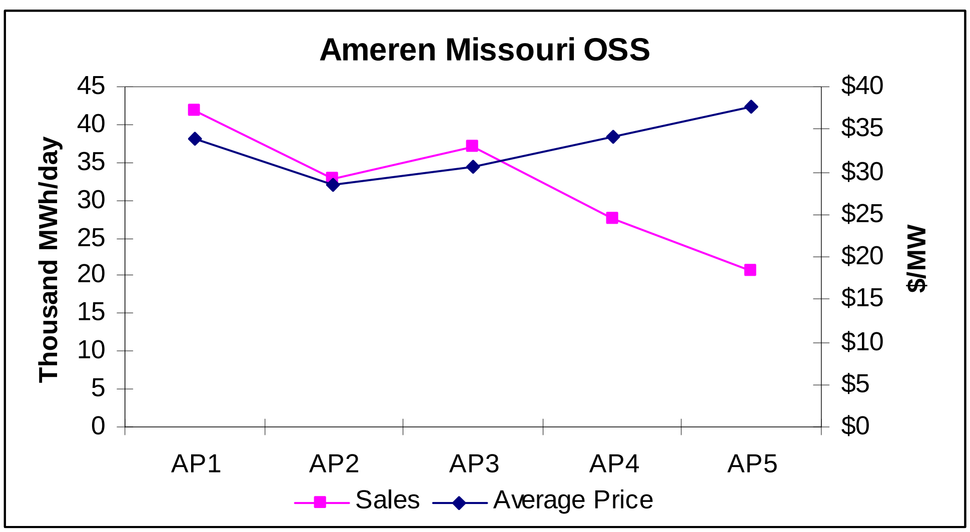
However, on February 5, 2009, Ameren Missouri filed an Application for Rehearing and Motion for Expedited Treatment in Case No. ER-2008-0318. Ameren Missouri sought new rates and a modified FAC tariff "to substantially modify the fuel adjustment clause the Commission approved in the Report and Order." According to Ameren Missouri's pleading, "approval of the Modified FAC Tariff would restore Ameren [Missouri] to the same position that it would have been in if the devastating ice storm [of January 28, 2009, which knocked out transmission that served Noranda Aluminum, Inc.] had not occurred." The Commission denied Ameren Missouri's application for rehearing on February 19, 2009. During the evidentiary hearing in File No. EO-2010-0255, Ameren Missouri witness Lynn Barnes answered Staff Counsel Jaime Ott's question about why Ameren felt the need to file a request for rehearing in the 2008 rate case seeking exclusion of all off-system sales resulting from the Noranda loss:

> I think that because we were in a situation where the order had just been granted and rates were not yet in effect, we felt that the first order would have been to change the -- or request a rehearing to modify the tariff to accommodate this request. Since the order that came from the Commission basically said not enough time to decide that situation on its merits, then we looked at the tariff that we had to live with and tried to figure out within the confines of the tariff what alternatives were available. [Transcript, Vol 2, p. 175, line 20 - p. 176, line 4]

This illustrates that when Ameren Missouri, was faced with an unexpected, unfortunate turn of events immediately after it was granted an FAC in Case No. ER-2008-0318—the loss of Noranda load— it searched for and found a way that it believes Ameren Missouri can use to retain for its shareholders most of the revenues it would have gotten from that load if it has not been temporarily lost. Staff recommends the Commission consider this action by Ameren Missouri as a basis for changing the sharing mechanism from 95%/5% to 85%/15%.

On December 1, 2010, Ameren Missouri filed for true-up of its first recovery period which initiated File no. ER-2010-0274. The FPA for AP1 was negative, i.e., Ameren Missouri's actual total energy cost for AP1 was less than the base energy cost for AP1. In its true-up filing, Ameren Missouri presented data which showed that the amount credited to customers' bills was less than what it should have been, i.e., the true-up amount was negative. However, in this true-up filing, Ameren Missouri has asserted the Net Base Fuel Costs established in Case No. ER-2008-0318 (the rate case where the Commission first approved a FAC for Ameren Missouri) were too high and, therefore, the difference between its actual total energy cost and the base energy cost should be smaller. In its true-up filing, Ameren Missouri argues the Commission has authority now to remedy this alleged error in Case No.ER-2008-0318 and, therefore, the true-up should result in additional monies being collected from its retail customers. After numerous meetings, both internal and with Ameren Missouri, Staff very recently came to the conclusion that for AP1, the kWh used in the calculation of the Net Base Fuel Cost in the tariff and the kWh used to determine the kWh sales during the accumulation period are inconsistent. Although Staff was unsure at the time this inconsistency existed in Ameren Missouri's last rate case, File No. ER-2010-0036, the parties reached a settlement that prospectively changed the calculation of Net Base Fuel Costs for Ameren Missouri's FAC tariff sheets in the tariff sheets that were filed and approved by the Commission. Since this was the first implementation of a FAC for Ameren Missouri since the late 1970's, it is likely there are other items that were also accounted for incorrectly. If the sharing mechanism is changed, it will give Ameren Missouri an incentive to review all the calculations and assumptions in its FAC more closely. Staff recommends the Commission consider the foregoing as a basis for changing the sharing mechanism from 95%/5% to 85%/15%.

Staff has also reviewed the monthly FAC data reports and information Ameren Missouri has provided through the five changes to its FPA rates. As previously discussed in this section of the report, there is much variability in Ameren Missouri's FPA. Staff reviewed the monthly reports to identify why there is the case. Ameren Missouri has provided twenty months of data from March 2008 through October 2010, which covers five accumulation periods. The graph below shows the amount of OSS and the average price per megawatt-hour ("MWh") Ameren Missouri received for its OSS in each accumulation period[30].



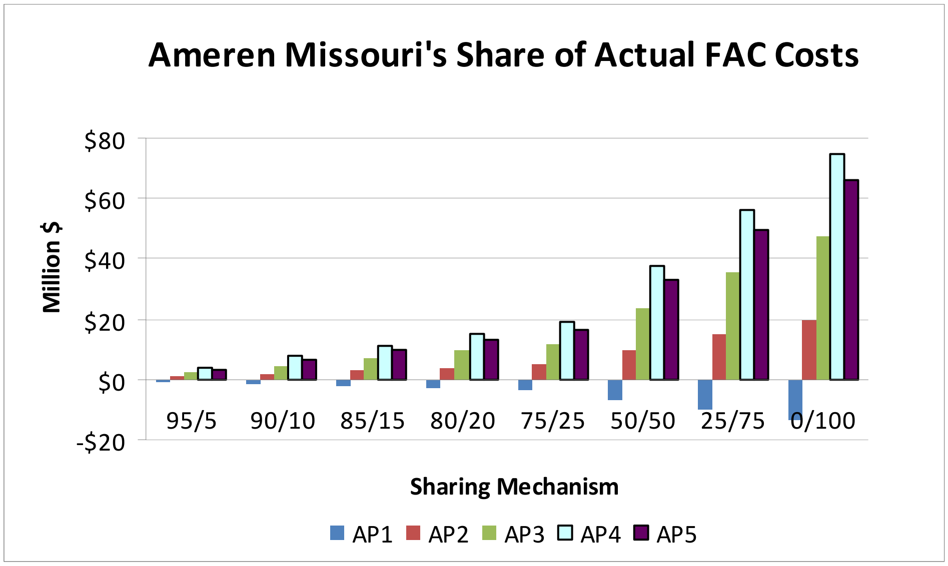
[30] Since it is Ameren Missouri's position that the AEP and Wabash contracts should not be flowed through the FAC, the data it provided did not include AEP and Wabash revenues or sales. However, Staff included AEP and Wabash sales and revenues its analysis.

This graph reveals that in the five accumulation periods since the Commission first approved Ameren Missouri's FAC, Ameren Missouri's OSS has decreased in four of the accumulation periods while the average price that Ameren Missouri has received dropped in AP2 but since has recovered to be higher than it was in AP1.

It may be that this graph shows exactly why a FAC should be disfavored. Since its fuel costs are passed through to customers, there is little or no incentive for a utility to reduce fuel costs and make OSS. However, there are some factors that have impacted Ameren Missouri's ability to make OSS that need to be considered when reviewing this graph and Ameren Missouri's fuel costs. As previously discussed, there was a 15% increase in retail usage between the two summer accumulation periods (AP2 and AP5). It is to be expected that fuel costs would increase more than usage since higher cost generation is used as demand increases. Additionally, with higher retail usage, there is less opportunity to make OSS. Further, Ameren Missouri's lowest cost generation plant, the Callaway nuclear plant, was down for a planned outage in the spring of 2010, leaving less capacity and opportunity to make OSS and resulting in the use of higher cost generation plants to meet its customer's requirements in AP4.

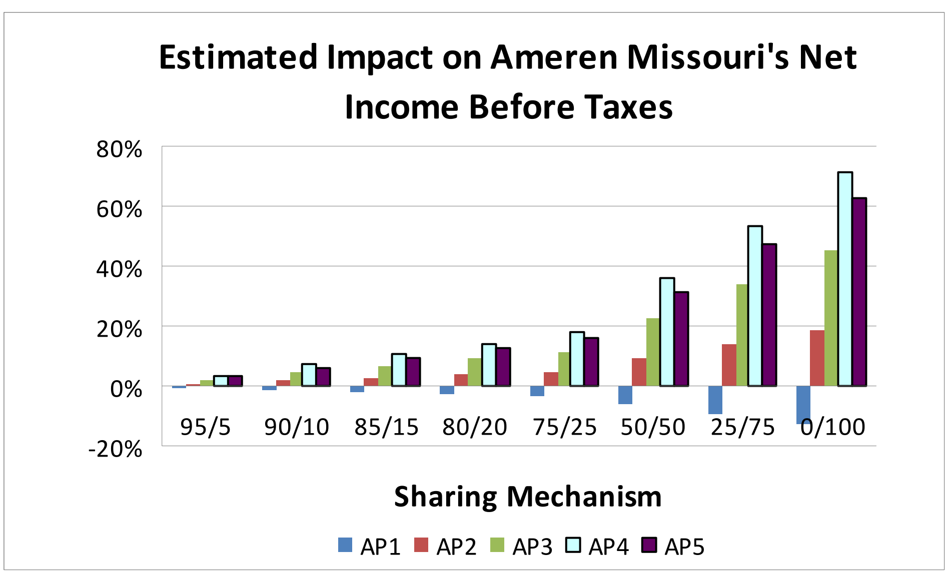
However, there is an additional factor that increased the amount of capacity available to Ameren Missouri for OSS. Ameren Missouri's Taum Sauk generation plant returned to service in April 2010, giving Ameren Missouri an additional 440 MW of capacity in AP4 and AP5. While Staff understands these factors influenced the OSS of Ameren Missouri during these accumulation periods, Staff still recommends the Commission, to give Ameren Missouri a greater incentive to make OSS, order the sharing mechanism changed from 95%/5% to 85%/15%.

Staff also reviewed the potential revenue impacts to Ameren Missouri of changing the sharing mechanism. The graph below shows the various percent shares of FAC costs Ameren Missouri would have kept and what costs it would have absorbed given other percentage sharing mechanisms for each of the five accumulation periods.



For the 95%/5% sharing mechanism where 95 percent of the difference in fuel costs is flowed back/recovered from the customers and 5 percent is kept/absorbed by Ameren Missouri, Ameren Missouri kept over $650,000 in AP1 and the most that it absorbed was 3.7 million in AP4. If it had not had an FAC (the 0%/100% sharing mechanism), Ameren Missouri would have kept $13.2 million in AP1 and the most that it would have absorbed would have been $75 million.

Another way to view the information is as a percentage of Ameren Missouri's net income before taxes. The graph below shows an estimation of these percentages for various sharing mechanisms using Staff's final net income before taxes in Ameren Missouri's last rate case.



This bar graph shows that with the current sharing mechanism of 95%/5% the estimated impact on Ameren Missouri's net income before taxes ranges from -0.63% to 3.57%. If Ameren Missouri did not have a FAC (the 0%/100% sharing mechanism), assuming that Ameren Missouri would have taken the same actions, the impact would have ranged from -12.6% to 71.4%. The impact of an 85%/15% sharing mechanism, given everything else remaining unchanged, would have ranged from -1.73% to 10.7%. However, it is unlikely that everything else would have remained unchanged. The effect of increasing the percentage of the increase in fuel cost for which Ameren Missouri would pay should incent Ameren Missouri to be more efficient. The Staff recommends the Commission consider the foregoing and rely on it as a basis for changing the sharing mechanism from 95%/5% to 85%/15%.

Staff Expert/Witness: Lena M. Mantle

D. Staff's Recommended Recovery Period Length Change

Currently Ameren Missouri's FAC accumulation periods are four months long. Two months after the end of the accumulation period Ameren Missouri files tariff sheets to change its FPA that have a sixty day effective date. Staff has 30 days to make its recommendation and the Commission has thirty days to act after Staff makes its recommendation. The difference between the actual total energy costs and the base energy cost is collected over a recovery period of the next 12 months. The time period between which costs are first incurred and the end of the recovery period is twenty months. This "regulatory lag" could be reduced by changing the time between the end of the accumulation period and the end of the recovery period (FAC cycle period).

The table below shows a comparison of the FAC cycle periods of GMO, Empire and Ameren Missouri.

Utility	Length of Accumulation Period	Time until change to FAC filed	Staff and Commission review time	Length of Recovery Period	FAC Cycle Period
GMO	6 months	1 month	2 months	12 months	21 months
Empire	6 months	1 month	2 months	6 months	15 months
Ameren Missouri	4 months	2 months	2 months	12 months	20 months

Changes could be made to Ameren Missouri's FAC cycle period that would reduce its FAC cycle period to as little as eleven months. This could occur if Ameren Missouri filed for a change to its FPA one month after the end of the accumulation period and the recovery period was only four months duration instead of twelve. This would be consistent with Empire's FAC where the accumulation periods are six months and the recovery periods are six months.

However, Staff is not recommending such a dramatic change to Ameren Missouri's FAC. Ameren Missouri states it selected a twelve-month recovery period to mitigate the impact of the FAC charges on its customers. For this reason Staff is recommending that the recovery period only be reduced by four months, from twelve months to eight months. This is consistent with GMO's FAC where recovery periods are twice the length of accumulation periods, i.e., accumulation periods are six months and recovery periods are twelve months.

The time between the beginning of the accumulation period and the end of the recovery period could be reduced another month if Ameren Missouri could shorten the time between when it ends a recovery period and when it files to change its FPA. However, since this time period is dependent upon the amount of time that Ameren Missouri needs to make its tariff filing, Staff is not recommending the Commission require Ameren Missouri to shorten the time between when an accumulation period ends and Ameren Missouri files for a change to its FPA.

Staff Expert/Witness: Lena M. Mantle

E. Correct Calculation of Change in Cost to Be Recovered

In its true-up filing, submitted in File No. ER-2010-0274, Ameren Missouri has asserted the Net Base Fuel Costs established in Case No. ER-2008-0318 (the general rate case in which the Commission first approved an FAC for Ameren Missouri) were too high and, therefore, the difference between Ameren Missouri's actual total energy cost and its base energy cost should be smaller (thus resulting in a larger true-up revenue request). Staff does not disagree that this energy cost difference should in fact be smaller, but unlike Ameren Missouri, Staff does not attribute the lack of such result to an improperly calculated NBFC rate.

The base energy cost for an accumulation period is calculated as the NBFC rate multiplied by the accumulation period kWh sales. Staff believes that there is an inconsistency in the accumulation period kWh sales as calculated by Ameren Missouri in conjunction with its true-up filing and the kWh sales originally used to calculate the NBFC rate that appears in the relevant portion of the Company's tariffs. Ameren Missouri calculated the accumulation period sales by using customer class billing month sales adjusted to the calendar month with associated losses from the Company's latest loss study. If Ameren Missouri had used its kWh usage at its MISO load node, there would not be the above-described inconsistency. The load at the Ameren Missouri MISO load node is measured – not calculated. Because such load can be aggregated over the exact time period that corresponds to both fuel and purchased power costs and OSS there is no need to adjust the kWh, as required by the method utilized by Ameren Missouri. The load at the MISO load node is also at the same voltage level as the loads used to calculate the NBFC rate and, therefore using such MISO load node would eliminate the need to adjust the accumulation period kWh to account for losses.

Therefore, Staff recommends that the Commission require the NBFC rate in Ameren Missouri's FAC tariff and the base energy of prospective accumulation periods be calculated using Ameren Missouri's load at its MISO load node. To be consistent, the forecasted recovery period kWh sales also need to be at the MISO load node.

The exemplar FAC tariffs that Staff will be filing in its Class Cost-of-Service and Rate Design report will reflect this change. In addition, expansion factors to account for losses at the level of the MISO load node will be included in the filing.

Staff Expert/Witness: Lena M. Mantle

F. Other Changes to Ameren Missouri's FAC

Staff agrees with the changes to the FAC proposed by Ameren Missouri witness Lynn Barnes with one exception. Ameren Missouri proposed to remove language that excludes the revenue from contract sales to municipalities from the FAC OSS revenues. As explained in the Jurisdictional Allocation section of this report, it is Staff's position that costs be allocated to the municipalities if all of the revenues from Ameren Missouri's contracts with the municipalities are not accounted for in this case.

Staff has other changes to the FAC tariff that it will propose in its Class Cost-of-Service Report that is to be filed on February 10, 2010. These changes are being proposed to clarify the tariff.

Staff Expert/Witness: Lena M. Mantle

G. <u>Additional Filing Requirements</u>

Just as it did in the last Ameren Missouri rate case, File no. ER-2010-0036, Staff is recommending the Commission to order Ameren Missouri to do the following to aid the Staff in performing FAC tariff, prudence and true-up reviews:

- As part of the information Ameren Missouri submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include Ameren Missouri's calculation of the interest included in the proposed rate;
- In addition to the monthly reports required by 4 CSR 240-3.161(5), provide Ameren Missouri's MISO Ancillary Services Market ("AMS") market settlements and revenue neutrality uplift charges;
- Maintain at Ameren Missouri's corporate headquarters or at some other mutually agreed upon place within a mutually agreed upon time for review, a copy of each and every nuclear fuel, coal and transportation contract Ameren Missouri has that is in effect;
- Within 30 days of the effective date of each and every nuclear fuel, coal and transportation contract Ameren Missouri enters into, provide both notice to the Staff of the contract and, at Ameren Missouri's corporate headquarters or at some other mutually agreed upon place, the contracts for review;
- Maintain at Ameren Missouri's corporate headquarters or provide at some other mutually agreed upon place within a mutually agreed upon time, a copy for review of each and every natural gas contract Ameren Missouri has that is in effect;
- Within 30 days of the effective date of each and every natural gas contract Ameren Missouri enters into, provide both notice to the Staff of the contract and at Ameren Missouri's corporate headquarters or at some other mutually agreed upon place a copy of the contract for review;
- Provide a copy of each and every Ameren Missouri hedging policy that is in effect for Staff to retain;
- Within 30 days of any change in an Ameren Missouri hedging policy, provide a copy of the changed hedging policy for Staff to retain;

- Provide a copy of Ameren Missouri's internal policy for participating in the MISO ASM, including any Ameren Missouri sales/purchases from that market for Staff to retain;
- If Ameren Missouri revises any internal policy for participating in the MISO ASM, within 30 days of that revision, provide a copy of the revised policy with the revisions identified for Staff to retain; and
- The monthly as-burned fuel report supplied by Ameren Missouri required by 4 CSR 3.190(1)(B) shall explicitly designate fixed and variable components of the average cost per unit burned including commodity, transportation, emission, tax, fuel blend, and any additional fixed or variable costs associated with the average cost per unit reported (Staff is willing to work with the Ameren Missouri on the electronic format of this report).

Staff Expert/Witness: Lena M. Mantle

H. Fuel Adjustment Clause Heat Rate and Efficiency Testing

4 CSR 240-3.161(3)(P) requires that when an electric utility files a general rate proceeding following the general rate proceeding that established its Rate Adjustment Mechanism (RAM) as described in 4 CSR 240-3.161(2), in which it requests that its RAM be continued or modified, an electric utility shall file the supporting information as part of its direct testimony:

> (Q) The results of heat rate tests and /or efficiency tests on all the electric utlity's nuclear and non- nuclear steam generators, HRSG, steam turbines and combustion turbines conducted within the previous twenty four (24) months:

Since the Commission authorized Ameren Missouri's FAC in its *Report and Order* in Case No. ER-2008-0318, effective February 6, 2009, Ameren Missouri is required by 4 CSR 240-3.161(3)(Q) to file supporting results of it heat rate testing when if files to continue or modify its fuel adjustment clause.

Ameren Missouri filed many of the results with the prefiled direct testimony of Lynn M. Barnes, and the Staff reviewed the results of those tests. However, Ameren Missouri did not file all the results as required by the rule with its direct testimony due to its voluminous nature. Ameren Missouri did make the all results available to Staff and others. Since results for the last two years were required to be submitted and Ameren Missouri has presented these results in the last two rate cases, Nos. ER-2008-0318 and ER-2010-0036, Staff easily found these results from those cases.

The testing methodologies utilized were consistent with the testimony of both Staff and Company witnesses in Case No. ER-2008-0318. Staff reviewed heat rate testing results of Ameren Missouri's generating units. The test results and associated data appear to be reasonable. There are now base line heat rate testing results for all of Ameren Missouri's generating plants to which future heat rate test results can be compared as a measure of the change of efficiency of the plant.

Staff recommends that, due to the voluminous nature of the results of the heat rate testing, in future rate cases the Commission grant Ameren Missouri a variance from the requirement to file all of its heat rate testing results in the case and instead allow Ameren Missouri to submit the heat rate testing results in electronic format with its work papers.

Staff Expert/Witness: Leon Bender

X. Other Items

A. Ameren Missouri Smart Grid Status[31] Rate Case ER-2011-0028

Ameren Missouri has been 100 percent deployed with Automated Meter Reading (AMR) since 2000 with 1.2 million meters in total, all owned by Ameren Missouri: 18,000 meters are configured for time-of-use/demand reporting and 5,000 are configured for 15-minute interval reporting for industrial and large commercial customer use. The remaining meters report daily kWh for residential and small commercial customer use. Customers can view daily usage, create a profile for their house and explore options for energy savings by utilizing the Ameren Energy Savings Toolkit.

In September 2009, Ameren Missouri conducted a study comparing the costs and benefits of AMR versus Advanced Meter Infrastructure (AMI). The basic difference between an AMR and AMI meter consists of the communication capabilities of the meters. The AMR meter is

[31] Information for this section was provided by Ameren Missouri through a workshop presentation filed in EFIS File No. EW-2009-0292, May 19, 2010, the company website and information provided during workshops and meetings with the MOPSC.

characterized by one-way or single direction communication between the meter to the utility. The AMI meter features two way communications between the meter and the utility which enables additional capabilities and features to be utilized. The results of the Ameren Missouri study concluded the following:

- AMR achieves most of the operational benefits of AMI without the two-way communications such as, automatic 'reads,' outage notification, tamper detection, and system load data.
- The operational benefits offered exclusively by AMI include remote connect/disconnect and remote meter programming/configuration.
- Conversion to AMI would require new meters, new communications infrastructure, a new software operating system, and billing system integration with a total conversion estimated at over $300 million.
- At the time of this study, the benefits of AMI did not outweigh the estimated costs of AMI deployment, but other AMI deployments are being closely monitored with plans to revisit this issue in the future.

The impact of Electric Vehicles (EV) and Plug-In Hybrid Electric Vehicles (PHEV) on the Smart Grid must be considered to determine what modifications if any, need to be implemented to accommodate the increase in the distributed electrical load. Ameren Missouri is taking receipt of two plug-in hybrid electric vehicle (PHEV) bucket trucks in 2011 as part of an Electric Power Research Institute (EPRI) demonstration project and is participating with St. Louis Clean Cities on a Plug-In Readiness Task Force as a means of monitoring initial discussions on how to create a local market for new PHEVs.

Ameren Missouri indicated in its workshop presentation that a August 2009 technology study concluded that there are no significant system effects or impact anticipated until PHEV penetration in their the service territory approaches approximately 150,000 vehicles.

Ameren Missouri's investments are focused on the electric system grid to improve service reliability, operating efficiency, asset optimization, and a robust energy delivery infrastructure. Ameren Missouri has approximately 2,300 line capacitors that are automated via one-way radio communications and approximately 800 tap changing substation transformers that are automated to adjust system voltage from commands issued by Distribution Control Offices. System voltage reduction has proven to work and Ameren Missouri-documented cases over 15 years show 1.0-1.2 percent demand reductions after programmed calls for 2.5 percent voltage reductions. Significant future infrastructure investments are required to take full advantage of this system optimization feature and the 1980s era legacy system of line capacitor control will need to be replaced. A new communications network infrastructure is required to support two-way communications with intelligent line devices like capacitors along with a new distribution management system platform. Ameren Missouri has deployed Supervisory Control and Data Acquisition (SCADA) to monitor substation transformers, equipment and circuits and transmit this data to a central location at 70% of their substations. Ameren Missouri has deployed nearly 400 distribution automation switching devices to detect fault and operate automatically to isolate system damage and restore power. Microprocessor based relaying has been deployed by Ameren Missouri at 50% of their substations.

Staff Expert/Witness: Randy S. Gross

Appendices

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation - David Murray

Appendix 3: Alphabetical Listing of Testimony Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J Bax

Alan J. Bax

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF LEON C. BENDER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Leon C. Bender, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Leon C Bender

Leon C. Bender

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

Nikki Senn

Notary Public

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Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF KOFI AGYENIM BOATENG, CPA, CIA, CFE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kofi Agyenim Boateng, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Kofi A. Boateng, CPA, CIA, CFE

Subscribed and sworn to before me this 7 day of February, 2011.

KAREN M. ROTTMANN
MY COMMISSION EXPIRES JULY 10, 2013
NOTARY SEAL
#09729133
ST. CHARLES COUNTY
NOTARY PUBLIC, STATE OF MISSOURI

Karen M. Rottmann
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF JOHN P. CASSIDY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John P. Cassidy, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John P. Cassidy

John P. Cassidy

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF WALT CECIL

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Walt Cecil, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Walt Cecil

Walt Cecil

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF DAVID W. ELLIOTT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David W. Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David W. Elliott
David W. Elliott

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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Commission Number: 07287016

Nikki Senn
Notary Public

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF LISA M. FERGUSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lisa M. Ferguson, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lisa M. Ferguson
Lisa M. Ferguson

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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Nikki Senn
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AFFIDAVIT OF GUY C. GILBERT, MS, PE, RG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Guy C. Gilbert, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

G. C. Gilbert

Guy C. Gilbert, MS, PE, RG

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn

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BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF RANDY GROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Randy Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy Gross

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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Nikki Senn
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AFFIDAVIT OF LISA K. HANNEKEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lisa K. Hanneken, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lisa K. Hanneken

Lisa K. Hanneken

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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OF THE STATE OF MISSOURI

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AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Shawn E. Lange, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Shawn E Lange
Shawn E. Lange

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

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney
Erin L. Maloney

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn
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AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

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

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray
David Murray

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

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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Commission Number: 07287016

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF STEPHEN M. RACKERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Stephen M. Rackers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Stephen M. Rackers
Stephen M. Rackers

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariff to Increase Its Annual Revenues for Electric Service	)))	File No. ER-2011-0028

AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A Rogers

John A. Rogers

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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OF THE STATE OF MISSOURI

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AFFIDAVIT OF MICHAEL E. TAYLOR

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael E. Taylor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael E. Taylor
Michael E. Taylor

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF HENRY E. WARREN, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Henry E. Warren, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E Warren

Henry E. Warren, PhD

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

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF CURT WELLS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Curt Wells, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Curt Wells

Curt Wells

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF SEOUNG JOUN WON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won

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

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016