MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT

COST OF SERVICE

UNION ELECTRIC COMPANY,
d/b/a AmerenUE

CASE NO. ER-2010-0036

Jefferson City, Missouri
December 18, 2009

**** Denotes Highly Confidential Information ****

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REVENUE REQUIREMENT COST OF SERVICE REPORT

COST OF SERVICE REPORT

I. Executive Summary

The Staff has conducted a review in Case No. ER-2010-0036 of all revenue requirement cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise Union Electric Company's d/b/a AmerenUE (AmerenUE or Company) Missouri jurisdictional revenue requirement. This audit was in response to AmerenUE's filing made on July 24, 2009, seeking to increase its Missouri jurisdictional retail rates to recover an additional approximately $402 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, 2009, with a true-up estimate through January 31, 2010. The Staff's recommended revenue requirement for AmerenUE is $190,395,678 to $200,000,000 based on a return on equity (ROE) range of 9.00% to 9.70%.

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 January 6, 2010.

II. Background of AmerenUE

AmerenUE 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. AmerenUE is wholly owned by Ameren Corporation, which also provides utility service in Illinois through the AmerenIP, AmerenCIPS and AmerenCILCO operating subsidiaries. AmerenUE also operates a natural gas distribution business in Missouri, which serves approximately 127,000 customers.

AmerenUE last sought to change its Missouri jurisdictional electric retail rates when it filed for a $251 million increase on April 4, 2008, in Case No. ER-2008-0318. In its Report and Order in that proceeding, which was effective February 6, 2009, the Commission granted AmerenUE a total annual increase in rates of approximately $161.7 million.

III. Test Year/True-Up Period

Though AmerenUE filed its case based upon a twelve month ending March 31, 2009, test year, it made adjustments to its case to reflect the impacts of anticipated changes through February 28, 2010; its requested true-up period end date. In the "Jointly Proposed Procedural Schedule, Related Procedural Items, And Test Year True-Up Cut-Off Date" (Joint Recommendation) filed on September 11, 2009, the Parties to the case agreed to a test year of twelve months ended March 31, 2009, and a true-up period ending January 31, 2010. The Joint Recommendation included the following language regarding the items that would be considered in the true-up.

> They [the Proponents] agree the true-up shall include all major changes in revenue, expenses, rate base and capital structure occurring through the cut-off date of January 31, 2010 and that the following items are anticipated to be trued-up as of the true-up date of January 31, 2010: revenues (including customer usage), payroll, depreciation and amortization expense, fuel and transportation prices, purchased power prices, rate base excluding cash working capital lead/lag days, cost of bank lines of credit, expense levels in trackers that have been implemented as a result of prior Commission order, income tax expense as affected by other true-up items. The Proponents agree that no one is precluded from proposing such significant additional item(s) as a proper true-up item, but the other parties should be timely notified in writing of a party's decision to propose an additional item(s) as a proper true-up item(s). The inclusion of an item in the preceding list of anticipated true-up items shall not preclude or limit any party from objecting to a specific item or event as inappropriate for treatment as a true-up item or as inappropriate for inclusion in the Commission's determination of the revenue requirements in this case. Further, inclusion of an item in the preceding list of anticipated true-up items shall not preclude or limit any party's discovery rights in any way as to the listed items or any other items or matters involved in this case.

On September 14, 2009, in its "Order Adopting Procedural Schedule And Establishing Test Year" the Commission ordered a true-up through January 31, 2010.

The Staff's revenue requirement as presented in its Accounting Schedules, includes expected changes for true-up based on current information. For example, the plant and depreciation reserve balances have been adjusted to reflect the anticipated additions through the January 31, 2010 true-up period. Fuel expense has also been adjusted, based on the January coal contract prices. The Staff expects to consider these items, as well as additional components of the cost of service during the true-up audit, consistent with the Joint Recommendation discussed above. The Staff is not endorsing now for the purpose of setting AmerenUE'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.

IV. Major Issues

The following are the major issues between the Staff and AmerenUE based on their respective prefiled direct 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 AmerenUE on the issue.

Return on Equity (ROE) – Issue Value – ($100 million difference based on the rate base presented by AmerenUE). The Staff is recommending a midpoint of 9.35% ROE. AmerenUE is recommending a 11.50% ROE. This issue is addressed in detail in Section V of this report by Staff witness David Murray.

Fuel, Purchased Power and Off System Sales – Issue Value – ($44 million difference). The majority of this difference relates to the different levels of fuel expense and off-system sales determined by AmerenUE and the Staff to be appropriate for the test year and the true-up period.

Payroll and Benefits – Issue Value – ($17 million difference). A significant portion of this difference relates to the inclusion of the effects of the voluntary and involuntary separation programs, which are reflected in the Staff's case, but occurred well after the Company filed its direct testimony. In addition, the level of benefits determined by AmerenUE is based on its 2009 budget, while the Staff's level is based on actual data through September 30, 2009.

There are other significant issues between the Staff and the Company, based upon their respective direct filings, with regard to power plant maintenance, depreciation expense and the cost of short-term debit financing. These issues are largely offset by the difference between the Company's and the Staff's direct filings with regard to the level of retail revenues.

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

V. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return (ROR) of 7.39 percent to 7.72 percent for Union Electric Company d/b/a AmerenUE (AmerenUE or Company). Staff's ROR recommendation is based on a recommended return on common equity (ROE) of 9.00 percent to 9.70 percent (midpoint 9.35 percent) applied to AmerenUE's March 31, 2009, common equity ratio of 47.39 percent. Staff's recommended ROE is primarily driven by its comparable company analysis using a multiple-stage discounted cash flow (DCF) methodology. Staff continues to believe that the DCF methodology is the most reliable method available for estimating a utility company's cost of common equity. However, as Staff had previously done in the Kansas City Power & Light Company (KCPL) and the KCP&L Greater Missouri Operations rate cases, Case Nos. ER-2009-0089 and ER-2009-0090, respectively, Staff decided to continue to deviate from its primary reliance on the constant-growth, single-stage DCF model (hereinafter referred to as the "constant-growth DCF"). Staff believes the current building cycle associated with the electric utility industry, which is causing near-term expected growth rates to be higher than long-term sustainable growth rates, requires expected cash flows to be evaluated in stages, which is the premise underlying a multi-stage DCF analysis.

Staff also employed a Capital Asset Pricing Model ("CAPM") analysis, using historical earned risk premiums and current U.S. Treasury bond yields, as a test of reasonableness of Staff's DCF estimate. Although Staff's CAPM analysis resulted in lower estimated costs of common equity than those derived using DCF methodologies, Staff did not adjust its ROE recommendation downward due to Staff's concerns about the current reliability of the CAPM using traditional inputs.

Staff has adopted Company Witness Michael G. O'Bryan's recommended capital structure and embedded costs of capital as of March 31, 2009, for purposes of this case. This capital structure consists of 47.39 percent common equity, 1.60 percent preferred stock, and 51.01 percent long-term debt.[1] Staff also adopted Company Witness O'Bryan's recommended

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[1] See Schedule MGO-E1 attached to O'Bryan's July 24, 2009 Direct Testimony.

embedded cost of debt of 5.967 percent and embedded cost of preferred stock of 5.189 percent as of March 31, 2009.[2]

Staff has prepared two (2) attachments and twenty (20) schedules that support Staff's findings and recommendations in the cost-of-capital area. The attachments contain explanations of the DCF and CAPM methodologies. These attachments are denoted as Attachments A and B, respectively, to this Report. The schedules present numerical support for Staff's ROR recommendation, and are numbered as Schedules 1 through 20. The attachments and schedules can be found in Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

Rate of return witnesses are mindful of the constitutional parameters that guide the determination of a fair and reasonable rate of return. These parameters were announced by the United States Supreme Court in two seminal cases, *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia* (1923) (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Company* (1944) (*Hope*).[3] The *Bluefield* Court specifically 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.[4]

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[2] See Schedules MGO-E2 and MGO-E4 attached to O'Bryan's July 24, 2009 Direct Testimony.
[3] ***Bluefield Water Works & Improv. Co. v. Pub. Serv. Comm'n of West Virginia,*** 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923); ***Fed. Power Comm'n v. Hope Nat. Gas Co.,*** 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943).
[4] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

Similarly, the *Hope* Court stated:

> The rate-making process, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated . . . that "regulation 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.[5]

From these Court decisions, Staff derives the following principles:

(1) A return consistent with comparable companies;

(2) A return sufficient to assure confidence in the utility's financial integrity;

(3) A return that allows the utility to attract capital; and

(4) A return consistent with current opportunity costs of investment.

While the legal requirements announced in the *Hope* and *Bluefield* cases have not changed, it is important to recognize that the methodology used to estimate a reasonable rate of return has evolved considerably since these cases were decided over 60 years ago. In fact, two of the most commonly used models in formulating rate of return (ROR) recommendations, the DCF model (as used in utility regulatory ratemaking proceedings) and the CAPM, did not become a part of mainstream finance until the 1960's. Likewise, the capital markets of today are not confined to regional boundaries when determining the most efficient use of capital.

In mainstream finance literature, the DCF model, as used in utility ratemaking, is alternatively referred to as the dividend growth, Gordon growth, and/or dividend discount model (DDM). In 1962 Myron J. Gordon reintroduced and expanded the model for the purpose of

[5] ***Hope,*** *supra,* 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345 (citations omitted).

estimating the cost of common equity.[6] Prior to this date, the model had primarily been used for stock valuation purposes.

The basis for the CAPM was provided in 1964 by William F. Sharpe, who received the Nobel Prize in 1990 for much of his work in producing the CAPM model.[7] The CAPM is frequently used by investment bankers to estimate the cost of capital for purposes of discounting future cash flows in order to estimate the present value of an enterprise.

It is generally recognized that authorizing an allowed return on common equity based on a utility's cost of common equity is consistent with a fair rate of return. It is for this very reason that the DCF method is widely recognized as an appropriate methodology to use in arriving at a reasonable recommended ROE for a utility. The concept underlying the DCF method is the ability to determine the cost-of-common-equity capital to the utility, which reflects the current economic and capital market environment. For example, a company may achieve an earned return on common equity that is higher than its cost of common equity. This situation will tend to increase the share price. However, this does not mean that this past achieved return is the barometer for what would be a fair authorized return in the context of a rate case. It is the lower cost of capital that should be recognized as a fair authorized return.

The authorized return should provide a fair and reasonable return to the investors of the company, while ensuring that ratepayers do not support excessive earnings that could result from the utility's monopolistic powers. However, this fair and reasonable rate does not guarantee any particular level of return to the utility's shareholders.

Although neither the DCF model nor the CAPM were used for making rate-of-return-recommendations during the period in which the *Hope* and *Bluefield* decisions were made, state commissions (including the Missouri Commission) throughout the country have accepted these methodologies for purposes of estimating rates of return for utility ratemaking.

C. Economic Information

The world and the U.S. economies are slowly recovering from a deep recession. Such transitional periods can make the estimation of a fair and reasonable cost of capital a tougher task

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[6] Frank K. Reilly and Keith C. Brown, *Investment Analysis and Portfolio Management*, Fifth Edition, The Dryden Press, 1997, p. 438.
[7] Zvie Bodie, Alex Kane and Alan J. Marcus, *Essentials of Investments,* Richard D. Irwin, Inc. 1992, p. 11.

than usual. Similarly, it is also difficult for utility commissions to determine a fair and reasonable allowed return during these economic conditions. I will provide this Commission with what I believe to be a reasonable estimate of the current cost of capital for a regulated electric utility company of at least investment grade credit quality.

Because of recent volatility in risk-free rates and implied equity risk premiums, it can be difficult to estimate the cost of equity using any cost of equity model, but particularly models that directly use a direct risk premium estimates, such as the CAPM and "bond yield plus risk premium" methodologies. The key in estimating the cost of equity for utility companies is to understand how investors view regulated utility companies in terms of risk and whether the current economic environment has impacted expectations for utilities' expected cash-flow growth.

1. Monetary Policy

On December 16, 2008, the Federal Reserve Bank ("Fed") cut the Fed Funds Rate to between zero and 0.25 percent, a level well below the historic low of 1.00 percent previously established under former Fed Chairman Alan Greenspan. This cut was clearly due to the Fed's concern about the state of the U.S. economy. The Fed normally reserves such aggressive actions for times in which it is concerned about the possibility of a deflationary price environment due to a severe contraction in the economy.

Although the current economic and capital market slump worsened during the fall of 2008, the Fed began to react to concerns about the economy in the fall of 2007 (the National Bureau of Economic Research declared in December 2008 that the U.S. has been in a recession since December 2007). Until September 18, 2007, the Fed had held the Fed Funds rate steady at 5.25 percent. However, in response to concerns about a tightening credit market (due in part to problems in the sub-prime market at the time) the Fed reduced the Fed Funds rate by a full 50 basis points (0.50%) on September 18, 2007. Over the remainder of 2007, the Fed lowered the Fed Funds Rate by additional 25 basis point (0.25%) increments, on October 31, 2007, and December 11, 2007. The Fed continued to lower the Fed Funds rate through most of the winter and spring of 2008 until they left the rate at 2.25 percent after April 30, 2008. The Fed appeared to not want to lower the Fed Funds rate any further due to concerns about sparking inflation during a period in which certain commodity prices, such as gasoline, were sky-rocketing.

However, shortly thereafter came the financial meltdown in which the Fed and the U.S. Treasury began to play a large role in orchestrating bailouts, mergers, acquisitions and allowing some financial institutions, such as Lehman Brothers, to go into bankruptcy. The Fed continued to lower the Fed Funds rate by two 50-basis point increments on October 8, 2008, and October 29, 2008, before making its last cut on December 16, 2008, to arrive at the current rate of zero to 0.25 percent.

The following comments were made in an article last month in the *Wall Street Journal (WSJ),*[8] about the Federal Reserves' Federal Open Market Committee meeting on November 3 and 4, 2009:

> The Federal Reserve affirmed its plan to keep interest rates 'exceptionally low' for a long time despite signs of economic recovery. But the Fed began to lay rhetorical groundwork for an eventual shift in its stance, suggesting that when the unemployment rate falls or if expectations for inflation turn up, it could change course…
>
> Fed officials are wrestling with conflicting challenges. On the one hand, the unemployment rate is so high and other measures of slack in the economy—such as unused factory capacity—are so great that inflation could keep falling even after a recovery takes hold. This low "resource utilization," as the Fed calls it, argues for keeping rates near zero for a long time.
>
> On the other hand, interest rates are so far below normal and the Fed as pumped so much money into the financial system that the central bank runs a risk of creating inflation or new speculative financial bubbles if officials miscalculate and overstimulate the economy…

It appears that although the U.S. economy grew in the past quarter, the Fed still has concerns about the sustainability of such growth without some continued economic stimulus. This would support the belief that the Fed will continue to keep the Fed Funds rate at a relatively low level. However, it appears that the Fed is hedging its bets on the need to keep the Fed Funds rate at historical lows. For example, in a statement issued after its meeting on November 3 and 4, 2009, the Fed cited qualifiers such as "low rates of resource utilization, subdued inflation trends and stable inflation expectations" required to keep rates at such low levels. Although the Fed's monetary policy typically focuses on the level of short-term rates, the rate of economic

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[8] Jon Hilsenrath, "Fed to Keep Rates Low Despite Pickup," *The Wall Street Journal*, November 5, 2009, p. A3.

growth (which the Fed is attempting to influence) tends to impact the cost of long-term borrowing.

Although the Fed tries to influence long-term capital costs through its adjustments to the Fed Funds rate, it does not have the same ability to set long-term rates as it does the Fed Funds rate. Long-term capital costs are market-based rates, which change based on a variety of market factors, with monetary policy being just one factor investors consider. Because long-term capital costs are the primary consideration in estimating a fair and reasonable rate of return, it is important to evaluate the long-term interest rate environment and understand factors that affect long-term rates.

2. Interest Rates, Bond Yields and Spreads

Long-term interest rates, as measured by Thirty-year Treasury bonds (30-year T-bonds), dropped to historically low levels at the end of 2008 and the early portion of 2009. However, these rates have since started to return to levels more consistent with recent years. As of November 2009, the yield on 30-year T-bonds averaged 4.31 percent (see Schedule 4-2), representing an increase from an all-time low in December 2008 of 2.87 percent. However, because of investors' concerns about the economy during the last quarter of 2008, the average utility bond yield increased to as high as 7.80 percent, as of November 2008. The spread between the utility bond yields and 30-year T-bond yields hit an historical high of 400 basis points in December 2008 (see Schedule 4-4). As of October 2009, the average utility bond yield had dropped considerably to an average of 5.64 percent. As a result, the spread between the utility bond yields and 30-year T-bond yields decreased to 145 basis points in November 2009, approximately 36% of the spread reached last December. The current 145 basis point spread is actually below the average spread of 155 basis points over the period 1980 through 2009 (see Schedule 4-4), which illustrates the stability that has returned to the capital markets. The decrease in utility bond yields to 5.64 percent represents a decrease of 216 basis points since its recent peak in November 2008.

Although average utility bond yields (inclusive of bonds rated from "Aa" to "Baa" by Moody's) have dropped back to levels experienced before the credit crisis in the fall of 2008, the spread between higher credit quality utility bonds and lower credit quality utility bonds remains higher than recent historical averages. Whereas, during economic environments before the credit crisis the spread between "A" rated utilities and "Baa" rated utilities was typically around 30 basis points, as of October 2009, this spread was 59 basis points according to the October 2009 *Mergent Bond Record*. The spread tends to be even smaller when evaluating the difference between "Aa" rated utility bonds and "A" rated utility bonds. While this spread is typically around 15 basis points, as of October 2009 this spread was 32 basis points. This results in a spread of 91 basis points between an "Aa" rated utility and a "Baa" rated utility. While this represents a 102 percent increase over the spread during the economic periods prior to the credit crisis, it is still much lower than the percentage increase in spreads that occurred in the fall of 2008, which approached an almost 400 percent increase over the traditional 45 basis point spread. Consequently, although the cost differential associated with being less creditworthy is still higher than before the credit crisis, this differential has declined significantly since the fall of 2008. It is important to understand changes in the spreads between debt-rating categories because this provides insight on the additional return investors require for incurring additional risk.

Because the monthly utility bond yield data available from Staff's subscription to *Mergent Bond Record* usually has about a one month lag, Staff reviewed more recent spot-yield information from Value Line. According to the December 11, 2009, issue of the *Value Line Selection and Opinion*, the yield on "BBB" rated utility bonds was 6.25 percent as of December 2, 2009. Based on the 30-year T-bond yield of 4.25 percent as of the same day, the spot-yield spread was 200 basis points. The spread has dropped by approximately 325 basis points from a spread of 526 basis points between the average yield for "BBB" rated utility bonds and the 30-year T-bond for the month of December 2008. Although Staff is providing information on spot yields for sake of providing current data, Staff does not recommend using spot yields when making cost-of-capital determinations, as it is important to evaluate yields over a longer period for purposes of making a responsible rate of return recommendation.

3. Equity Performance

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the October 16, 2009, issue of *The Value Line Investment Survey: Selection & Opinion*, for the third quarter of 2009 the Dow Jones Industrial Average (DJIA) increased by 15.0 percent, the Standard & Poor's (S&P) 500 increased by 15.0 percent, the NASDAQ Composite Index (NASDAQ) increased by 15.7 percent, and the Dow Jones Utility Average (DJUA) increased by 5.4 percent. According to the same publication, for the nine months ended September 30, 2009, the DJIA increased by 10.7 percent, the S&P 500 increased by 17.0 percent, the NASDAQ composite increased by 34.6 percent, and the DJUA increased by 1.7 percent.

It is noteworthy that the DJUA has generally lagged the other indices. It is not surprising that other indices have generally outperformed the DJUA considering that investors may be expecting an improvement in the economy. Stocks of industries that tend to be more reactive to economic cycles -- so-called "cyclical stocks" -- tend to outperform industries that are less reactive to economic cycles during periods in which the economy begins to improve. However, it is also important to understand that the changes in the indices mentioned above do not include dividend returns, which tend to be a majority of the return component for regulated utility companies.

Although the DJUA is one of the more widely published utility indices, it should be used with caution for purposes of drawing inferences about possible trends in regulated utilities' cost of capital because many of the companies in the DJUA have non-regulated operations that contribute to their performance. Three of Staff's comparable companies are included in the DJUA. These three companies are American Electric Power Co., PG&E Corp., and Southern Company, Inc. Therefore, Staff does not consider the DJUA to be a good proxy group for AmerenUE. However, comparing utility index results to the rest of the stock market can provide insight on the value being placed on utility stocks in general.

Utility indices can also vary in their results. For example, the Value Line Utilities Group, which is composed of "utility" companies followed by Value Line, increased by 7.6 percent for the third quarter of 2009, which is a greater than the 5.4 increase for the DJUA. The Value Line Utilities Group increased by 1.9 percent for the nine months ended September 30, 2009, compared to the DJUA's increase of 1.7 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation.

4. Macroeconomic Environment

It is also worthwhile to review some economic indicators for purposes of evaluating the reasonableness of a rate of return recommendation in this case. Although a reasonable DCF analysis captures investors' expectations about future economic conditions, investors will review some of this information to arrive at their own conclusion about a fair price to pay for utility stocks in today's environment.

The Value Line Investment Survey: Selection & Opinion, November 27, 2009, estimates inflation to be 1.10 percent for 2009, 1.80 percent for 2010 and 2.50 percent for 2011. The Congressional Budget Office, *The Budget and Economic Outlook: An Update*, August 2009, forecasts an inflation rate of 0.80 percent for 2009, 1.50 percent for 2010, and 1.20 percent for 2011 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury bills, are estimated to be 0.20 percent in 2009, 0.60 percent in 2010, and 2.00 percent in 2011 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.10 percent in 2009, 4.50 percent in 2010, and 5.00 percent in 2011.

The most recent weekly rate for three-month U.S. Treasury bills was 0.06 percent (see Schedule 5). The most recent weekly rate for long-term Treasury bonds was 4.29 percent (see Schedule 5).

Gross domestic product (GDP) is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to decrease by 2.50 percent in 2009, increase by 2.20 percent in 2010, and increase by 3.10 percent in 2011. The Congressional Budget Office, *Budget and Economic Outlook: An Update*, August 2009, stated that real GDP is forecast to decrease by 2.50 percent in 2009, increase by 1.70 percent in 2010, and 3.50 percent in 2011 (see Schedule 5).

The Value Line Investment Survey: Selection & Opinion, December 4, 2009, stated the following in its Economic and Stock Market Commentary:

> **On the one hand, homebuilding has stalled.** For example, recently issued figures show that housing starts fell 10.6% in October, a larger decline than expected. That setback followed months of flattish activity. Bad weather and uncertainty about the extension of the home-buyer tax credit---the credits have since been extended---get much of the blame for pushing starts down to their lowest levels since April. Building permits,

> often viewed as a barometer of future building activity, also fell. Builders, understandably, are quite wary, as foreclosures are rising and supplies of unsold homes---albeit lower than they were---remain too high to stoke a strong building recovery.
>
> **On the other hand, resale activity has come back strongly,** with sales of existing homes now at their highest level in almost two years. Moreover, inventories of unsold homes continue to fall---an encouraging recovery sign. Unfortunately, prices continue to slide as well, and this probably will delay an even stronger comeback, as will the slow response time by lenders, and the still-tight credit conditions. Our feeling is that the worst of the long housing slump is over, but that a sustainable recovery will be a long and uneven process.
>
> **Elsewhere, the U.S. economy is on a three steps forward, two steps backward path.** Reports for October showed a nice rebound in consumer spending, mild strength in industrial production, a lesser increase in the leading indicators than in the prior month, a surprising drop in durable goods orders, and a modest gain in consumer confidence. The U.S. gross domestic product---which rose by a downwardly revised 2.8% in the third quarter---may increase by a slightly more modest 2.0% - 2.5% in the current period.
>
> **Meanwhile, we are at an earnings crossroads.** Third-quarter results were better than expected, and totals for the fourth quarter should exceed the prior-year's tallies. However, sales gains remain elusive, and we'll need to see progress here if earnings growth is to be sustained in 2010 at a good level, in our opinion.
>
> **Investors are still buying,** as the stock market is now much more richly capitalized than it was earlier in 2009, when equities were in a freefall.
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> **Conclusion:** We remain generally constructive on the market, although we acknowledge that valuations are no longer as attractive as they were. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

5. Summary

The economic and capital market environment over the last few months has left a lasting impact on investors. However, the impact on the cost of capital depends on the risk profile of the company. While even less risky companies experienced a spike in their cost of capital in the fall of 2008 and early 2009, it appears that much of this fear, at least for companies with stable cash flows, has subsided. In fact, utility bond yields have returned to levels not seen since approximately 2006, before credit markets began to tighten due to the credit events associated with sub-prime loan concerns and before the "credit collapse" of late 2008. However, spreads between lower quality, investment grade public utility debt ("Baa" as rated by Moody's, which is the equivalent to a "BBB" credit rating from S&P) and higher quality, investment grade public utility debt continue to be higher than before the credit crisis. However, later in this Report, Staff will provide information from utility company equity analysts that cast doubt as to whether financial analysts that follow utility stocks are using higher required rates of return due to recent economic and capital market events. This leads Staff to believe that some of the contraction in the stock market may have been due to pessimism about future growth in the economy.

D. Overview of Ameren's and AmerenUE's Operations, Financing and Staff's Proposed Approach for Estimating AmerenUE's Cost of Capital

Estimating a fair and reasonable cost of capital requires an understanding of the subject entity's business operations, credit quality, and capitalization.

1. Business operations.

The following excerpt from Ameren's Form 10-K filing with the SEC for the 2008 calendar year provides a good description of Ameren's current business operations:

> Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 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 liabilities. These subsidiaries operate rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and non-rate-regulated electric generation businesses in Missouri and Illinois, as discussed below. Dividends on Ameren's common stock and the payment of other expenses by the Ameren and CILCORP holding companies are dependent on distributions made to it by its subsidiaries. See Note 1 – Summary of Significant Accounting Policies to our financial statements under Part II, Item 8, of this report for a detailed description of our principal subsidiaries.
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> - UE operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri.
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> - CIPS operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

- Genco operates a non-rate-regulated electric generation business in Illinois and Missouri.

- CILCO, a subsidiary of CILCORP (a holding company), operates a rate-regulated electric and natural gas transmission and distribution business and a non-rate-regulated electric generation business (through its subsidiary, AERG) in Illinois.

- IP operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.

In Note 1 to Ameren's Notes to Financial Statements, Ameren provides the following description of AmerenUE'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.

2. Credit Quality

AmerenUE's current S&P corporate credit rating of "BBB-" is only one notch above "junk" status. The following is an excerpt from an August 27, 2009, S&P credit-rating report on AmerenUE:

> The ratings on Union Electric Co. (UE) reflect Ameren Corp.'s consolidated credit profile. UE's ratings also reflect its excellent business profile and Ameren's significant financial profile. Ameren's subsidiaries also consist of utilities, Central Illinois Public Service Co., Central Illinois Light Co. (CILCO; a subsidiary of CILCORP Inc.), and Illinois Power Co. Ameren's unregulated businesses include Ameren Energy Generating Co. and Ameren Energy Resources Generating Co. (a subsidiary of CILCO). Ameren also has an 80% ownership of Electric Energy, Inc., which operates non-rate-regulated electric generation facilities. As of June 30, 2009, Ameren had about $8.4 billion of total debt outstanding. Based on the combination of future earnings, cash flow, and capital expenditures, we currently view Ameren as about 60% regulated and 40% unregulated.
>
> In most circumstances, Standard & Poor's will not rate a wholly owned subsidiary higher than the parent. Exceptions can be made on the basis of structural or regulatory insulation, which in the case of UE, in our view, is

> not present. Therefore, regardless of UE's excellent business profile and relatively healthy financial condition as a stand-alone basis, Standard & Poor's views the rating on UE to be affected by Ameren's non-regulated businesses.
>
> UE's excellent business profile reflects the more recent constructive regulatory order in Missouri that approved an annual electric rate increase of $162 million and also approved a fuel adjustment clause that will allow for the recovery of 95% of the company's fuel and purchase power expenses (after netting for off system sales revenue). Although we recognize that the past winter's ice storms and the ongoing recession will continue to have an impact on the company's load growth and cash flow measures, nevertheless, we view the overall regulatory environment in Missouri as a credit enhancing situation compared to several years ago.
>
> The consolidated satisfactory business profile reflects Ameren's non-regulated businesses, partially offset by the improvements to both the Illinois and Missouri regulatory environments…

Moody's and Fitch also rate AmerenUE and its debt. Moody's currently assigns a "Baa2" credit rating to AmerenUE and Fitch assigns a "BBB+" credit rating to AmerenUE. Although Moody's and Fitch cite concerns about Ameren's weaker affiliates when commenting on AmerenUE's credit rating, these rating agencies give weight to AmerenUE's stand-alone business and financial risks.

3. Capitalization

Schedule 6-1 presents Ameren's and AmerenUE's 2008 calendar year-end historical capital structures in dollar terms for the past five years and for the period ending September 30, 2009. Schedule 6-2 presents the capital structure information in percentage terms. As can be seen in this Schedule, AmerenUE's 5-year historical common equity ratio has been slightly higher than that of Ameren's. As of September 30, 2009, AmerenUE had a slightly lower common equity ratio than that of Ameren.

E. Determination of the Cost of Capital

A utility company's actual cost of capital at any point in time depends, in part, on the types of capital supporting the utility company's assets. The usual capital components are: common equity, long-term debt, preferred stock, and short-term debt. A weighted cost for each capital component is determined by multiplying each capital component ratio by the appropriate embedded cost (in the case of debt) or by the estimated cost of common equity component (in the case of common equity). The individual weighted costs are then summed to arrive at a total weighted cost of capital. This total weighted average cost of capital (WACC) is synonymous with the fair rate of return for the utility company.

A company's authorized WACC is considered a just and reasonable rate of return under normal circumstances. From a financial viewpoint, a company employs different forms of capital to support, or fund, the assets of the company. Each different form of capital has a cost, and these costs are weighted proportionately to fund each dollar invested in the assets. Assuming that the various forms of capital are reasonably balanced and are valued correctly, the resulting total WACC, when applied to rate base, will provide the funds necessary to service the various forms of capital. Thus, the total WACC corresponds to a fair rate of return for the utility company.

F. Capital Structure and Embedded Costs

After Staff's own investigation, Staff decided to accept Company Witness Michael G. O'Bryan's capital structure recommendation for AmerenUE. Staff has reproduced the capital structure provided by Mr. O'Bryan in Schedule 7, contained within Appendix 2, attached to this Cost of Service Report. The resulting capital structure consists of 47.39 percent common stock equity, 51.01 percent long-term debt and 1.60 percent preferred stock.

The appropriate capital structure to use in estimating the cost of capital for a utility should be noncontroversial if the utility's operations are viewed by the investment community as "stand-alone" operations. If not stand alone, then the determination of the appropriate capital structure can be much more elusive. Unfortunately, in the case of AmerenUE, there is no unanimous view on the part of credit rating agencies as to whether AmerenUE's risk profile is primarily driven by its own business and financial risk. This lack of consensus caused Staff to investigate whether it is appropriate to use AmerenUE's or Ameren's capital structure for ratemaking purposes in this case.

Most of Staff's recent relevant and detailed experience with evaluating the appropriateness of a subsidiary or parent company capital structure is based on Staff's analysis in the last three Missouri-American rate cases, Case Nos. WR-2003-0500, WR-2007-0216 and WR-2008-0311. In these cases, Staff was concerned about the fact that Missouri-American's parent company, American Water Works Company, was aggregating the long-term debt financing of its subsidiaries at the parent company level. Additionally, American Water Works Company issued debt and preferred stock at the holding company level and invested this capital as "equity" into its subsidiaries. This caused Staff to take the position that Missouri-American did not have a "legitimate" capital structure.

Applying these principles and experiences to the present case, AmerenUE issued all of its long-term debt as of March 30, 2009, but has received short-term debt proceeds from Ameren. However, as of the test year in this case, Ameren did not have any long-term capital outstanding other than equity capital. Additionally, a review of Ameren and AmerenUE's average common equity ratios for the most recent five years shows common equity ratios that are consistently similar, which eases any potential Staff concerns about possible manipulation of AmerenUE's capital structure for ratemaking purposes. However, Staff does note that the capital structure of Ameren's non-regulated subsidiary, Ameren Generating Company (AmerenGenco), does not contain much more equity than its regulated affiliates, even though it is considered to have a much higher amount of business risk. This causes Staff some concern that Ameren's regulated entities, which includes AmerenUE, are indirectly supporting the credit quality of AmerenGenco.

After considering the various factors above, Staff decided the use of AmerenUE's capital structure is acceptable at this time. This decision is consistent with Staff's position in at least the two most recent AmerenUE rate cases, Case Nos. ER-2007-0002 and ER-2008-0318.

Because Company Witness Michael G. O'Bryan appears to have accurately represented AmerenUE's ratemaking capital structure, Staff will accept this capital structure for purposes of the test year in this case. However, Staff does have a data request pending requesting an explanation for a discrepancy Staff noticed in Mr. O'Bryan's capital structure and that shown in the balance sheet AmerenUE provided in response to Staff Data Request No. 0270.

Staff should also note that the recommended ratemaking capital structure does not contain short-term debt. This is not because AmerenUE does not issue short-term debt for purposes of funding its operations. This is because AmerenUE currently carries average construction work in progress (CWIP) balances that exceed the average amount of short-term debt outstanding. Short-term debt is the primary financing source for construction and the financing costs capitalized in the allowance for funds used during construction (AFUDC) predominantly reflect the cost of short-term debt. Therefore, AFUDC should be the mechanism for recovery of short-term debt costs (and also where the benefit of lower short-term debt costs will be realized). The short-term debt capitalization rate should be based on reasonable costs associated with short-term debt, including reasonable costs of credit facilities. This treatment is consistent with the methodology of determining the embedded cost of debt in which issuance costs are included with interest expense in determining the costs. Of course, to the extent long-term debt is included in the capital structure, this is the means of recovery of the issuance costs associated with long-term debt.

G. Cost of Common Equity

Staff estimated AmereUE's cost of common equity by applying cost of equity methodologies to a proxy group. Staff primarily relied on the DCF methodology to estimate the cost of equity, but Staff also tested the reasonableness of its DCF estimate by performing a CAPM analysis. Staff first attempted to estimate the cost of common equity by performing its traditional constant-growth DCF analysis (explained in detail in Attachment A), which simply consists of adding an estimated dividend yield with a projected constant growth rate to arrive at an estimated cost of equity. However, due to Staff's concerns about being able to reliably estimate a sustainable constant-growth rate for the electric utility industry, Staff decided a multi-stage DCF analysis is better suited for the current situation. Staff explains its multi-stage DCF analysis in more detail later in the ROR section of the Cost of Service Report. Staff tested the reasonableness of its DCF analysis using the CAPM (explained in detail in Attachment B), which consists of adding a market risk-adjusted risk premium to a risk-free rate to estimate the cost of equity. Staff also reviewed other information, such as cost of equity estimates and expectations from the investment community, to further test the reasonableness of its estimated cost of equity.

1. Proxy Group

The Staff started with a list of 65 market-traded companies classified as electric utility companies by Value Line (see Schedule 8). To this list Staff applied certain criteria in order to develop a proxy group comparable in risk to that of AmerenUE. Staff's criteria, and the resulting effects, are as follows:

1. Classified as an electric utility company by Value Line;

2. Stock publicly traded:

This criterion did not eliminate any companies;

3. Classified as a regulated utility by EEI or not followed by EEI:

This criterion eliminated thirty-one companies;

4. At least 70 percent of revenues from electric operations or not followed by AUS:

This criterion eliminated nine additional companies;

5. Ten year Value Line historical growth data available:

This criterion eliminated two additional companies;

6. No reduced dividend since 2006:

This criterion eliminated six additional companies;

7. Projected growth available from Value Line and Reuters:

This criterion eliminated four additional companies;

8. At least investment grade credit rating:

This criterion did not eliminate any additional companies; and,

9. Company-owned generating assets:

This criterion eliminated one additional company.

This final group of twelve publicly-traded electric utility companies (the comparables) was used as a proxy group to estimate the cost of common equity for risks consistent with electric utility companies. The comparables are listed on Schedule 9.

<u>2. Constant-growth DCF</u>

Staff attempted to initially estimate the proxy group's cost of common equity using its traditional constant-growth DCF analysis in this case, which in most situations is considered to be ideal for estimating the cost of common equity for regulated utilities due to the maturity of the regulated utility industry. However, due to unsustainable projected earnings growth rates and the wide disparity between historical and projected growth rates, Staff believes it is much more difficult to reliably estimate an appropriate constant growth rate for purposes of this analysis.

Because the estimated growth rate used in a constant-growth DCF analysis must be sustainable, if there isn't any consistency in historical and projected growth rates, then estimating a reliable constant growth rate becomes a more difficult task. Notwithstanding Staff's concerns, Staff will explain the steps it took in performing its traditional constant-growth DCF analysis.

The first step Staff performed in its constant-growth DCF analysis was to estimate a growth rate. The Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected DPS, EPS and BVPS growth rates for the comparables. Schedule 10-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 10-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 10-3 presents the averages of the growth rates shown in Schedules 10-1 and 10-2. As can be seen from these schedules, historical growth rates have been fairly volatile. Because of this volatility, Staff hesitated to assign substantial weight to the historical growth rates in estimating investors' expectations of future growth for the proxy group. Consequently, Staff analyzed projected growth rates to determine if these growth rates might be a reliable proxy for investors' expectations of future long-term growth in the proxy group's stock price.

Staff analyzed the projected DPS, EPS and BVPS as estimated by the Value Line analyst for each company over the next five years (see Schedule 11). As demonstrated in the schedule, the Value Line projected growth rates are much more stable than historical growth rates, but there is still a relatively wide dispersion in projected EPS growth (3.00 percent to 9.50 percent). Staff also evaluated equity analyst earnings estimates provided on *Reuters.com*. As can be seen from this data, the projected growth rates range from 3.00 percent to 15.00 percent and have a standard deviation of 3.19 percent. Although this wide dispersion alone causes Staff concern about relying too heavily on these growth rates in a single-stage, constant growth DCF analysis, Staff also believes investors would not consider an average projected growth rate of 6.02 percent (column 3 of Schedule 12) to be sustainable for the long-run.

Although Staff does not believe it is currently prudent to rely on historical and projected growth rates to estimate a sustainable growth rate for its constant-growth DCF model analysis, Staff nevertheless plugged in a growth rate of four to five percent because this gives some consideration to some of the high estimated EPS growth rates in the near-term, but also recognizes that these growth rates are not sustainable due to the fact that they are higher than long-term projected economic growth rates provided by the Congressional Budget Office (4.1 percent for 2014 through 2019) and used by the Energy Information Administration (EIA) for purposes of estimating energy consumption (2.5 percent real GDP plus Staff's assumed adder of 2 percent for inflation). As Staff will demonstrate when explaining its multi-stage DCF analysis, these assumed long-term growth rates are somewhat high when considering long-term forecasted demand for electricity.

It is important to ensure the selection of stock prices that reflect investors' current expectations of the business and economic climate. Staff believes the use of stock prices for the most recent three months through the end of November 2009 is reasonable, as this reflects investors' analysis of the current economic conditions over a period that covers the amount of time in a quarterly period. It should be noted that Staff's use of three months of average stock prices for the comparable group is different from its past practice of using four months of stock prices. Staff decided to make this change because most financial data is reported based on three months of data.

The monthly high/low averaging technique minimizes the effects on the dividend yield that can occur due to short-term volatility in the stock market. Schedule 14 presents the average high/low stock price for each comparable for the period of September 1, 2009, through November 30, 2009.

Column 1 of Schedule 15 indicates the expected dividend for each comparable over the next 12 months as projected in the most recent Value Line report. Column 3 of Schedule 15 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected average dividend yield for the comparables of 5.20 percent. Considering the Commission's position in its Report and Order in the most recent Union Electric rate case, Case No. ER-2008-0318, in which the Commission supported quarterly-compounding of dividends, it is important to note that Staff did not adjust the dividend yield for quarterly compounding. Staff is attempting to estimate investors' expectations and because the Value Line dividend yield does not reflect quarterly compounding, Staff is not convinced that investors' analyze the expected dividend yield on a quarterly-compounded basis.

As shown on Schedule 15, Staff's estimate of the proxy group's cost of common equity based on the projected dividend yield and a growth rate range of 4.00 to 5.00 percent is 9.20 percent to 10.20 percent.

3. Multiple-Stage DCF

Staff's multi-stage DCF assumes three different stages of growth in dividends: years 1-5, years 6-10 and year 11 through infinity. Although it is impossible to discount expected dividends through infinity, it is possible to extend the period long enough where the discounting of additional dividends does not have a meaningful impact on the cost of equity estimate. Staff extended its third stage to 200 years. Although this methodology may seem complex on its face, it is simply determining the discount rate that causes current stock prices to equal the present value of future expected dividends.

Staff recently used this approach in the last Kansas City Power & Light Company ("KCPL") rate case, Case No. ER-2009-0089, and the KCPL Greater Missouri Operations ("GMO") rate case, Case No. ER-2009-0090. In those cases, Staff deemed a multi-stage DCF analysis to be the most appropriate approach considering the fact that the economic and capital markets at the time were in a state of flux. Considering that near-term economic growth rate projections at the time were pessimistic and projections for long-term economic growth were relatively lower than analysts projected growth rates for electric utilities, Staff did not believe analysts' growth rates could be sustainable considering the macroeconomic environment. Even though the economic and capital market environment have stabilized since those cases, based on Staff's understanding of the continued large investment cycle of the electric utility industry, analysts' higher projected growth rates reflect this near-term expected rate base growth and will not be sustainable for the long-term. Staff believes this justifies Staff's continued reliance on the multistage DCF methodology for estimating an electric utility company's cost of common equity.

Although the capital markets have stabilized compared to the fall of 2008 through the spring of 2009, Staff believes the characteristics of the electric utility industry, in which historical growth rates and projected growth rates are widely divergent and projected growth rates are not sustainable, justifies the continued use of a multiple-stage DCF analysis to reliably estimate the cost of equity for an electric utility company, such as AmerenUE. Although other rate of return witnesses have used two-stage and multiple-stage DCF analyses in past rate cases in which Staff sponsored testimony, Staff did not believe such methodologies to be necessary in those instances due to the stability of the economy, the capital markets and 5-year projected growth rates for regulated electric utilities that were more consistent with sustainable growth rates. Although the capital markets have improved recently, near-term projected growth rates for the electric utility industry are higher than the projected long-term economic growth rates provided in the Congressional Budget Office's update to its *2009 The Budget Economic Outlook*. If growth is not expected to be constant and/or sustainable, then a multiple-stage DCF analysis is appropriate.

Multiple-stage DCF methodologies are usually intended for industries and/or companies that are in the early stages of their growth cycles. However, if an industry and/or the economy are going through a period of transition, then a multiple-stage DCF analysis can address the non-constant growth situation that is present. However, there may be sectors within the utility industry that are not as largely impacted by changes in the economy. For example, in Staff's recent ROR testimony in both the Missouri Gas Energy rate case, Case No. GR-2009-0355, and The Empire District Gas Company rate case, Case No. GR-2009-0434, Staff believed the constant-growth DCF methodology was reliable due to relatively constant historical and projected growth rates. However, if Staff had performed a multi-stage DCF analysis in those cases, Staff's estimated cost of common equity would have been lower, considering that these growth rates were not likely to be sustainable in perpetuity. Many finance textbooks have used the utility industry as an example for an appropriate situation to use the constant-growth DCF model, so this methodology is still sound as long as the capital and economic environments are fairly stable and the industry is mature and stable.[9][10]

Because of the factors discussed above, Staff believes a multi-stage DCF analysis will provide the most reliable cost of common equity estimate, as long as reasonable growth rates are used at the various stages in the analysis. As with the constant-growth model, it is not the model alone that allows for reliable results, it is the reasonableness of the inputs that provide reliable results. Although the reasonableness of early-stage estimated growth rates are important in a multi-stage DCF analysis, the perpetual growth rate used will be the primary driver of the final cost of common equity estimate. While a DCF analysis of companies/industries in the early stages of their growth cycle, i.e. supernormal growth companies, may use GDP as an estimate for the perpetual growth rate, this is not reasonable for mature industries that are simply going

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

through transition impacted by construction cycles and/or economic uncertainty. It is entirely reasonable to expect that utility companies will return back to a growth rate consistent with their real growth (plus a factor for inflation). This should cause electric utility companies to settle on a perpetual growth rate of around three percent, which Staff will support later in this section of the Cost of Service Report.

Although Staff continues to have concerns about whether investors accept equity analysts' optimistic earnings growth rate projections for purposes of making investment decisions, Staff does realize that many electric utility companies are involved in a significant amount of construction that may improve their earnings when these projects are reflected in rates. Therefore, Staff chose to give full weight to the analysts' earning growth estimates for the first five years of its DCF analysis and partial weight to these analyst growth rates in years six through ten. However, Staff does not believe any of these growth rates are reasonable for a perpetual growth rate because they are not sustainable. For this reason, Staff chose to rely on projected electricity consumption growth and an inflation factor to estimate investors' expectations of long-term sustainable growth for an electric utility company. Staff relied on the Energy Information Administration's (EIA) projection of long-term electricity consumption for a long-term sustainable demand growth rate. The EIA provides comprehensive data on both historical and projected growth in various sectors of the energy industry. EIA projects that electricity demand will increase by approximately 1.0 percent per year for the period 2007 through 2030 for all sectors of the economy.[11] This projected demand growth is consistent with the downward trend in electricity usage dating back to 1950. More specifically, starting in year 2020 (the year in which the third stage of Staff's third stage DCF growth rate would start), EIA projects a 0.93 percent annual growth rate through 2030.

For purposes of expected inflation Staff reviewed the Congressional Budget Office's (CBO) projected general annual inflation rate of approximately 2.0 percent used for the period 2016 through 2019.[12] Although this projected inflation rate does not extend past 2019, this appears to be a good proxy for long-term inflation expectations. However, this estimated inflation rate is lower than that which is implied by the yield difference between 20-year nominal

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[11] "2009 Annual Energy Outlook," p. 71, *Energy Information Adminstration*

[12] "The Budget and Economic Outlook: An Update," August 2009, Supplemental Table 2-6, *Congressional Budget Office.*

treasury bond and 20-year treasury inflation protected securities (TIPS). The yield on a 20-year nominal treasury bonds averaged 4.24 percent in November 2009, whereas the yield on the 20-year TIPS bond averaged 1.90 percent in November 2009. This implies that in November 2009 investors required an inflation premium of 2.34 percent. The implied inflation premium was 2.12 percent in October 2009 and 2.01 percent in September 2009. If the inflation premiums for these three months are averaged, then this implies an approximate inflation premium of 2.16 percent. Considering all of this information, Staff decided a 3.1 percent growth rate is reasonable for purposes of its multi-stage DCF analysis.

A perpetual growth rate of around three percent appears to be consistent with long-term expected growth even before the slow down in the economy. According to an article in the October 2004 issue of *Public Utilities Fortnightly* entitled "The Dividend Yield Trap," regulated electric utilities long-term growth expectations should not be much more than one to three percent. The article goes on to state that the average long-term growth rate of 4.6 percent for the component utilities of the Lazard Core Utility Index was too optimistic and a "long-term growth proposition is closer to two to three percent, and then only if the industry is able to successfully execute on cost-cutting initiatives. In this regard, it is worth noting that during the past 30 years the industry has achieved a compound average growth rate of only one percent." These lower perpetual growth rates are also consistent with many of the perpetual growth rates used by equities analysts' when performing discounted cash flow analysis on utilities. Staff believes that this information further supports the reasonableness of Staff's selection of a 3.1 percent perpetual growth rate.

Instead of reducing the 5-year analyst growth rate estimates down to the perpetual growth rate in year six (this is the assumption in most 2-stage DCF analyses, which results in a lower cost of equity estimate), Staff decided to allow for a gradual decline from years six through ten and then applied the perpetual growth rate starting in year eleven because projecting company-specific growth rates past this time is futile.

When performing its constant-growth DCF analysis, Staff does not traditionally make the assumption that next year's dividend will grow at the rate of projected earnings growth because investors rarely expected the dividend to grow at this rate in the short-term. However, for purposes of performing its multi-stage DCF analysis in this case, Staff did make this simplifying assumption because the dividend yield is not one of the explicit components of a multi-stage formula.

The multi-stage DCF analysis is equivalent to determining the internal rate of return (IRR) for a possible investment. The IRR is the discount rate that makes the present value of all future cash flows equal to the cost of the initial investment. In most cases, if the IRR is higher than the cost of capital, then the company will make the investment. As with many of the methodologies used to estimate the cost of common equity for utility companies in rate case proceedings, this model was adapted to solve for the equity investors' required rate of return. There are many situations in which cash flows are discounted to determine a current value of a proposed investment. For example, investment advisors discount expected future cash flows of a possible investment by the cost of common equity of the operation in order to provide an opinion on the "fair value" of a proposed investment. Staff will explain later why it believes its estimate of the cost of common equity using a multi-stage DCF methodology is supported by the cost of equity used by investment analysts for purposes of evaluating the intrinsic value of electric utility stocks.

Staff provides its multi-stage DCF analysis recommendation on Schedule 17. Schedule 17 shows the proxy group's overall average cost of common equity and Staff's recommended range based on this average. Staff does not recommend an adjustment to the estimated proxy group's cost of common equity because AmerenUE's credit rating is similar to that of the proxy group. However, Staff will revisit its consideration of an adjustment due to testimony provided by Company Witness Lee R. Nickloy at the evidentiary hearings for AmerenUE's interim rate increase request, in which Mr. Nickloy indicated that AmerenUE's bonds are trading as if they were "A" rated, which may imply a lower cost of equity than that of the proxy group. However, until Staff has the opportunity to investigate this evidence, it will not make an adjustment. However, Staff's initial findings using a multi-stage DCF analysis is an estimated of cost of common equity in the range of 8.70 percent to 9.70, with a point estimate of 9.20 percent.

Staff does not believe its multi-stage DCF analysis should be adjusted upward for quarterly compounding as the Commission requested in its recent Report and Order in Case No. ER-2008-0318. Estimating the cost of common equity necessarily involves making certain simplifying assumptions. In this case, Staff assumed that investors would receive dividends in the near future at the rate of earnings growth when in reality this will not likely happen. If Staff were to assume that investors would be able to reinvest these extra dividends that they will not receive, then this would only inflate the estimated cost of equity. According to Value Line, the projected growth rate in dividends for Staff's proxy group over approximately the next 5 years is around 4.50 percent. However, Staff's multi-stage DCF analysis assumed that this dividend would grow from years one through five at a rate of 6.02 percent per year. If Staff discounted the total dividends Value Line expects the proxy group to pay through 2013 by Staff's recommended cost of equity of 9.35 percent, this would result in an average present value for these dividends of $62.05. However, when Staff discounts the dividends assumed in its multi-stage DCF analysis using the same discount rate, the result is a present value of $64.56 for these dividends. Because Staff's multi-stage DCF analysis assumes investors will receive more in dividends (at least in the early stages) than they are likely to receive, this methodology requires a higher discount rate (and therefore a higher indicated cost of equity than appropriate) to cancel out the assumption of receiving a higher amount of dividends sooner rather than later. Over this 5-year period, the discount rate (cost of common equity) has to be increased to 11.14 percent in order to achieve a present value of dividends equivalent to the present value of the Value Line predicted dividends. Because Staff has reviewed equity analysts analysis that shows that the analysts use lower equity discount rates in their analysis, Staff's believes this supports its opinion that electric utility stock values are supported by lower discount rates rather than higher expected growth in cash flow.

4. Capital Asset Pricing Model

Staff also performed its traditional CAPM cost of common equity analysis on the comparable companies. However, due to recent significant stock market declines through the end of 2008, these CAPM results should not be given much consideration in this case. Before the significant market contraction that occurred from the fall of 2008 through the spring of 2009, Staff previously indicated that it believed the risk premium estimates based on the differences in earned returns between stocks and risk-free bonds may be too high considering higher stock valuation levels. Now, Staff believes estimates using earned return spreads may be too low considering the significant decreases in equity returns through the end of 2008. Consequently, the reliability of cost of common equity results obtained from performing a CAPM analysis or risk premium analysis is heavily dependent on the estimated risk premium used to determine the cost of common equity.

Therefore, if the inputs in the CAPM analysis are not vigorously tested to determine if they are consistent with current implied market risk premiums, then a CAPM analysis will not yield reliable results. However, because the estimation of implied equity risk premiums is often done by using some variation of the DCF methodology, Staff believes any such attempt in this case to estimate the equity risk premium for purposes of the using the CAPM will only be as reliable as the DCF analysis used to estimate this equity risk premium. If the DCF analysis does not appear to be reliable, then any risk premiums estimated using a DCF analysis will be unreliable. Consequently, Staff focused its time and effort on performing a multiple-stage DCF analysis to provide what it believes to be the most reliable results in the current capital and economic environment. Nevertheless, Staff performed a CAPM analysis to show the impact recent market events have had on a CAPM analysis using traditional inputs.

The CAPM requires estimates of three main inputs, the risk-free rate, the beta and the market risk premium. For purposes of this analysis, Staff's used an average yield on Thirty-year U.S. Treasury Bonds for its risk-free rate. In this case, the Staff decided to use an average monthly yield for the most recent three months (September, October and November 2009). This is a slight variation from Staff's traditional approach of using the most recent average monthly yield available, which in this case would have been November 2009. However, as discussed during the recent evidentiary hearing in the MGE rate case, Case No. GR-2009-0355, because yields fluctuate just as stocks do, it seems both logical and appropriate in this case for Staff to average this yield for a three month period, as is done for stock prices in Staff's DCF analysis to determine the dividend yield. The three-month average yield was 4.23 percent and this was obtained from the St. Louis Federal Reserve website. If Staff had continued to use the most recent monthly yield, its CAPM cost of common equity estimate would have been 8 basis points higher.

For the second variable, beta, Staff used Value Line's betas for the comparable group of companies. Schedule 16 contains the Value Line betas for the comparables. The average beta for the comparables was 0.66.

The final term of the CAPM is the market risk premium (R_m - R_f). The market risk premium represents the expected return from holding the entire market portfolio, less the expected return from holding a risk-free investment. The Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.

The first risk premium Staff used was based on the long-term, arithmetic average of historical return differences from 1926 to 2008, which was 5.60 percent. The second risk premium used was based on the long-term, geometric average of historical return differences from 1926 to 2008, which was determined to be 3.90 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2009 Yearbook.*

Schedule 16 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the long-term arithmetic average risk premium and the long-term geometric average risk premium produces estimated costs of common equity of 7.94 percent and 6.81 percent, respectively. Staff does not believe these current CAPM results are reliable indicators of the cost of common equity for the proxy group and therefore, AmerenUE. Although for the reasons mentioned above Staff does not believe these current CAPM results should be used for purposes of recommending a fair and reasonable return on common equity for AmerenUE, they do illustrate the impact the stock market declines that occurred in 2008 have had on CAPM analyses using historical earned return risk premium differences.

H. Further Tests of Reasonableness

Because the Commission has expressed concerns in past rate cases that Staff's estimated cost of common equity may be too low, Staff has researched information from the investment community in the last few rate cases to test the reasonableness of its recommendations. Staff has continued to discover information from these sources that supports cost of equity estimates in the 8 to 9 percent range.

Staff requested from AmerenUE all financial analyst reports published on Ameren since January 1, 2008, in Staff Data Request No. 0200. AmerenUE response indicated the following:

> There are many dozens of responsive financial analyst research reports published since January 2008 and we obtain virtually all of these reports via Thomson Reuters' ThomsonOne product. Our contact with Thomson does not allow us to provide copies to outside parties. Therefore these reports will be made available for inspection at a mutually agreeable date and time by contacting Mary Hoyt.

Because ROR witnesses are endeavoring to "read the minds" of investors in estimating the cost of common equity, Staff decided it should investigate these reports in order to test the reasonableness of its recommendation. Although Staff did not make copies of any of the reports AmerenUE allowed Staff to investigate (according to Ameren this would have violated their subscription agreement), Staff did take notes on specific items in these reports that supports the reasonableness of Staff's estimated cost of common equity.

Although there are currently several financial firms that analyze Ameren's equity, there has been some reduction in the amount of coverage due to recent financial turmoil in the financial services industry. Staff reviewed research reports (both general industry reports and Ameren-specific reports) published by many firms, which included at least the following: KeyBanc Capital Markets, Goldman Sachs, Hilliard Lyons, Barclays Capital, J.P. Morgan, Bank of American/Merrill Lynch, Citigroup, Jesup & Lamont, and Edward Jones.

Although all of these firms provided a variety of information that may be helpful for purposes of making electric utility investment decisions, Staff found commentary from Goldman Sachs and Bank of America to be especially relevant in testing the reasonableness of Staff's estimated cost of common equity, and for that matter, any parties' estimated cost of common equity in this case.

Goldman Sachs' research reports covering the electric utility industry consistently provide the cost of equity discount rates they use when analyzing electric utility stocks. In more recent research reports covering the electric utility industry, Goldman Sachs has been using a cost of common equity of 9 percent. Goldman Sachs uses this cost of common equity when performing dividend discount model (DDM) analysis on publicly-traded electric utility companies. The DDM is synonymous with the DCF as that term is used in regulatory terminology. Because Goldman Sachs performs a multi-stage DCF analysis, their model also includes an estimate of a terminal/perpetual growth rate. Goldman Sachs consistently uses a 2.5 percent terminal growth rate, which compares to the 3.1 percent terminal growth rate that Staff used in its analysis. If Staff had used a 2.5 percent terminal growth rate in its multi-stage DCF analysis, the mid-point of its estimated cost of common equity would have been approximately 8.8 percent.

In a Goldman Sachs electric utility industry research report as recent as October 12, 2008, Goldman Sachs had used an 8.5 percent cost of common equity. The terminal growth rate in that analysis was also 2.5 percent.

It is important to be aware that although these are the costs of common equity that Goldman Sachs considers appropriate when discounting expected dividends for electric utility companies, this does not necessarily translate into the cost of common equity implied by stock prices at any given point in time. For example, during the stock market contraction that occurred in March 2009, Goldman Sachs' analysts indicated the following on page 3 of its March 10, 2009, research report, "Reiterate Neutral Coverage View; POR replaces NVE as CL Buy," by Michael Lapides, Jaideep Malik, Zac Hurst and Neil Mehta:

> **If implied costs of equity remain high or authorized RoEs do not increase, companies will likely decrease longer-term capital spending and rate base growth – reducing our 4-5 year EPS growth outlook below current levels.** Our implied DDM analysis shows that the implied cost of equity has increased by approximately 27% since March 2008 to levels near 11.3% - above where regulators recently set authorized returns on equity. Authorized returns are key given the increased costs of equity and debt – if authorized rates of return set by regulators do not increase, many companies will face challenges of earning a WACC-like return on capital investment, driving them to reevaluate and potentially reduce longer-term discretionary spending where possible. Alternatively, if the cost of equity declines as stock prices increase or bond yields decrease, companies will face less economic pressure to reduce capital spending. (emphasis not added)

It is important to emphasize that the Goldman Sachs' analysts were estimating the implied cost of common equity at a time when the S&P 500 had hit its lowest level in almost 15 years (the lowest closing index level occurred on March 9, 2009). Clearly the capital markets were much more stable in the past, and currently as well, so this does not support an estimated cost of equity anywhere near 11.3 percent under normal circumstances. The fact that Goldman Sachs' estimate of the electric utility industry's cost of equity at the peak of the recent capital market crisis is barely over 11 percent gives some context as to the reasonableness of Staff's recommendation under a stable capital economic environment. In fact, Staff's recommendation is higher than Goldman Sach's estimation of implied costs of equity under stable capital market situations. Goldman Sachs indicates that the implied cost of equity in March 2009 was 27 percent higher than it was in March 2008. After performing some simple algebra, this translates into an implied cost of common equity of 8.9 percent in March 2008. Considering that capital markets are much more stable than they were in March 2009, Staff believes the 8.9 percent cost of equity is more relevant in the current capital market environment.

Staff also found some commentary in an October 30, 2008, Bank of America equity report, "Revising Generation Valuation and P/E Multiple: Reducing Price Targets for Higher Market Discount and Lower Asset Valuation," by Shelby Tucker, Lauren B. Duke and Ellen Ngai, to be very insightful. Staff found the following specific commentary on page 2 of this report:

> We are revising our price target for the electric utility sector to account for 1) lower unregulated generation asset valuation and 2) lower P/E multiples for regulated entities. Our generation asset valuation still assumes $7.50 per mcf long-term natural gas price but increases the cost of coal, sets a range of 14% to 16% internal rate of the return, and reduces the marginal heat rate to account for a looser demand/supply equation. For our regulated utilities, we derive a base case 11.3x forward P/E for a traditional low-growth utility versus 13.3x prior to this report. Our new P/E assumes a 7% equity premium (versus the current 8.3%, but still well above the traditional 4%-5%), a 0.7 beta, a 4% risk-free rate, a 3% dividend growth, and a 65% dividend payout ratio. The computation can be found in Figure 9 on page 7. We have adjusted our enterprise value-to-EBITDA multiple down by 0.5x for most other assets that are not valued on a P/E basis.

Once again, although the above commentary indicates the analysts increased their equity risk premiums, a break-down of the individual components of their cost of capital analysis results in a cost of equity discount rate slightly below 9 percent. The specifics of computations were shown in Figure 9 in the report, but because Staff was not allowed to copy this information, Staff cannot attach this information to its Cost of Service Report. However, simply multiplying the 0.7 beta times the 7 percent equity risk premium results in a beta-adjusted risk premium of 4.9 percent. Adding this risk premium to the risk-free rate of 4 percent, results in a cost of equity discount rate of 8.9 percent. Based on the information in the parentheses, it appears that the Bank of America analysts considered this to be a more "normalized" risk premium compared to what they believed was implied by the capital markets at the time. If these analysts had used the 8.3 percent risk premium, their estimated cost of common equity would have been approximately 9.81 percent. However, it is also important to note what they considered to be a "traditional" risk premium of 4 to 5 percent, which most likely was used prior to the credit crisis and the significant decline in risk-free rates.

Another very important part of the analysis shown in the above quoted commentary from the Bank of America equity research report is the assumed 3 percent dividend growth rate. This further supports Staff's use of a 3.1 percent terminal growth rate in its multi-stage DCF analysis.

Although Staff did not discover any Ameren-specific cost of common equity estimates in the various equity research reports it reviewed, this was not necessarily surprising to Staff. It appears that investment analysts tend to use a cost of common equity they believe to be consistent with the risks inherent in the industry and not attempt to make any specific adjustments for specific characteristics of the company. Based on various commentary Staff reviewed, it appears that investment analysts provide some general qualitative assessment of a stock's attractiveness based on price to earnings multiples of the company's stock compared to industry averages. Based on this commentary, it appears most investment analysts currently view Ameren as a diversified/hybrid utility due to its non-regulated operations, which according to an April 22, 2009 research report published by Citigroup, made up 44 percent of Ameren's consolidated operations. Consequently, Ameren's stock price probably is discounted due to the additional risks associated with non-regulated operations and, therefore, its cost of equity would be higher than is appropriate for AmerenUE's regulated utility operations.

In order to further test the reasonableness of Staff's estimated cost of common equity for AmerenUE's operations, Staff reviewed expected returns for various asset classes provided by the Missouri State Employees' Retirement System (MOSER's) on its website. Please see http://www.mosers.org/About-MOSERS/Reports-Research/Summit-Strategies-Capital-Markets-Assumptions.aspx. According to this information, the expected returns for large capitalization domestic equities is only 8.50 percent. Because regulated electric utility companies exhibit less risk than the broader market (as measured by betas), this demonstrates the reasonableness of an estimated cost of common equity in the 8 to 9 percent range.

Another test of reasonableness is a "rule of thumb" estimate of the cost of common equity based on current costs of debt being incurred by electric utility companies. According to the textbook *Analysis of Equity Investments: Valuation* (2002) by John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey (used as part of the curriculum in the

Chartered Financial Analyst Program), a typical risk premium added to the yield-to-maturity (YTM) of a company's long-term debt is in the 3 to 4 percent range. Because utility stocks behave much like bonds, I would not add more than a 3 percent risk premium to arrive at a rough estimate of the cost of common equity. As of October 2009, Moody's "A" rated bonds and "Baa" rated bonds were yielding 5.55 percent to 6.14 percent respectively. If you add 3 percent risk premium to these yields, the indicated cost of common equity is 8.55 percent to 9.14 percent.

Based on all of Staff's cost of equity analyses and consideration of all of the other independent information Staff reviewed to test the reasonableness its analyses, Staff believes a fair cost of common equity estimate in this case is in the range of 9.00 percent to 9.70 percent, with a mid-point of 9.35 percent. Staff may adjust its recommended cost of common equity based on any decisions the Commission makes regarding AmerenUE's request for an interim rate increase and any changes in AmerenUE's capital structure as of the true-up period in this case.

Although the Staff recommends that the Commission rely primarily on the Staff's cost-of-common-equity recommendation in this case when authorizing a fair rate of return, the Staff recognizes that the Commission has expressed a preference in past cases to at least consider the average authorized returns as published by the Regulatory Research Associates (RRA).

According to RRA, the average authorized ROE for electric utility companies for the first three quarters of 2009 was 10.43 percent based on 22 decisions (first quarter – 10.29 percent based on nine decisions; second quarter – 10.55 percent based on ten decisions; third quarter – 10.46 percent based on three decisions).

The average authorized ROE for electric utility companies for 2008 was 10.46 percent based on 37 decisions (first quarter – 10.45 percent based on ten decisions; second quarter – 10.57 percent based on eight decisions; third quarter – 10.47 percent based on eleven decisions; fourth quarter – 10.33 percent based on eight decisions).

Although average authorized ROEs tend to garner the most attention in rate cases, it is also important to consider average authorized rates of return (RORs) to provide some context for average authorized ROEs. Some companies' costs of debt may cause their ultimate authorized return to be somewhat higher than the average. Although the cost of debt is only adjusted in extraordinary circumstances (for instance, in past Aquila rate cases, the cost of debt was adjusted to make it consistent with investment grade costs), there may be concerns about the reasonableness of these costs. Because it is the overall ROR (not the quoted average authorized ROE) that is applied to rate base to determine the revenue requirement, it would appear that this average would also be important in testing the reasonableness of the total cost of capital.

The average authorized ROR for electric utilities for the first three quarters of 2009 was 8.17 percent based on twenty decisions (first quarter – 8.19 percent based on eight decisions; second quarter – 8.05 percent based on nine decisions; third quarter – 8.48 based on three decisions).

The average authorized ROR for electric utilities in 2008 was 8.25 percent based on thirty five decisions (first quarter – 8.36 percent based on nine decisions; second quarter – 8.21 percent based on seven decisions; third quarter – 8.32 percent based on ten decisions; fourth quarter – 8.09 percent based on nine decisions).

While Staff's recommended ROE and ROR for AmerenUE are below the average authorized returns published by RRA, this does not necessarily mean that parties to those cases have not estimated lower costs of common equity. Additionally, although Staff's recommended ROR is below the averages authorized RORs, this could also be due to higher costs of debt for the published cases. For example, for the 2009 published RORs, Staff noticed some RORs in the 7 percent range even though the common equity ratios were similar to that of AmerenUE's in this case.

Because Staff has not researched the specifics of any of these cases, Staff cannot inform the Commission with any certainty as to why its recommendation is below the average authorized ROEs or RORs.

I. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.39 percent to 7.72 percent was developed for AmerenUE (see Schedule 20). This rate was calculated by applying an embedded cost of long-term debt of 5.967 percent and a cost of common equity range of 9.00 percent to 9.70 percent to a capital structure consisting of 47.39 percent common equity, 51.01 percent long-term debt and 1.60 percent preferred stock. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that AmerenUE be allowed to earn a return on its rate base in the range of 7.39 percent to 7.72 percent, with a point recommendation of 7.56 percent.

Through Staff's analysis, it believes that it has developed a fair and reasonable return. Staff's estimate of the cost of common equity is consistent with discount rates and expected returns used by those in the investment community. Because these are sources with no connection to the utility rate setting process, Staff believes this is the type of information that should be reviewed to test the fairness and reasonableness of a recommended return on equity.

Staff Expert/Witness: David Murray

VI. Rate Base

A. Plant in Service and Depreciation Reserve

1. Plant in Service - Accounting Schedule 3

This Schedule reflects, by account, the rate base value of AmerenUE's plant in service estimated through January 31, 2010. The Staff has adjusted AmerenUE's plant balances to allocate a portion of the Company's general plant to AmerenUE's retail natural gas business. These adjustments to the March 31, 2009 test year balances are reflected in Adjustments to Plant - Accounting Schedule 4.

Staff Expert/Witness: Lisa M. Ferguson

2. Depreciation Reserve - Accounting Schedule 5

Accounting Schedule 5, Depreciation Reserve, reflects, by account, the rate base value of AmerenUE's depreciation reserve estimated through January 31, 2010. As it did with Plant in Service, the Staff has adjusted AmerenUE's depreciation reserve balances to allocate a portion of the Company's general plant depreciation reserve to AmerenUE's retail natural gas business. These adjustments to the March 31, 2009 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 Company did not calculate a lag, or the Staff determined that the lag AmerenUE 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 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, whereas the aging reports reflect accounts that will eventually end up as bad debts.

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, 2009.

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 AmerenUE's average balance of materials and supplies inventory that was maintained during the 13 months ending March 31, 2009. 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

The Staff included a 13-month average of coal inventory through March 31, 2009 adjusted to reflect coal prices that will be in effect as of January 31, 2010. For nuclear fuel inventory, the 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 September 2009. The Staff used 13-month averages through September 2009 to determine the inventory quantities for stored gas and oil. The Staff will continue to examine the actual inventory quantities for all of these items through the end of the true up period ending January 31, 2010.

Staff Expert/Witness: Roberta A. Grissum

E. Customer Demand Programs Regulatory Asset

<u>1. Update On AmerenUE's DSM Programs</u>

Staff is including this DSM resource status information in this report, because when Staff sent AmerenUE a letter (attached as Schedule ACM-1 within Appendix 3) inquiring whether or not AmerenUE intended to notify the Commission of the changes in its implementation plan as required in 4 CSR 240-22.080(10), AmerenUE informed Staff via a letter (attached as Schedule ACM-2 within Appendix 3) that 4 CSR 240-22.080(10) requires the utility to only notify the Commission when its preferred plan changes and AmerenUE did not consider the delayed implementation of its demand-side resources a change in its preferred plan adopted and approved by AmerenUE.

Staff has reviewed AmerenUE's demand-side resource plans from the chart entitled "AmerenUE DSM Program Implementation Plan"[13] filed as part of AmerenUE's resource plan filing in Case No. EO-2007-0409 on February 5, 2008 and completed the table below to inform the Commission of the actual in-service dates of programs and the in-service dates in the resource acquisition strategy implementation plan adopted and approved by AmerenUE in its last electric resource planning filing made on February 5, 2008.

continued on next page

[13] See page 85 of AmerenUE's "Risk Analysis and Strategy Selection" section of its Electric Resource Planning filing made in Case No. EO-2007-0409

The progress AmerenUE has made can be seen in the table below:

Program Name	In-Service Date In Resource Plan	Actual In-Service Date
C&I Standard Incentive	February 11, 2009	February 11, 2009
C&I Custom Incentive	September 1, 2008	February 11, 2009
C&I Prescriptive Incentive	November 28, 2008	
C&I Retro-commissioning	September 1, 2008	July 25, 2009
Commercial New Construction	February 2, 2009	May 3, 2009
Industrial Interruptible Tariff	July 18, 2008	see note 1
C&I Demand Credit	September 1, 2008	July 1, 2009
CPP w/Smart Thermostat	March 2, 2009	
Residential Direct Load Control	October 31, 2008	
ENERGY STAR Homes	March 2, 2009	
Residential HVAC Diagnostic & Tune-up	January 1, 2009	
Residential Lighting & Appliances	November 28, 2008	May 22, 2009
Residential Multifamily	November 28, 2008	June 6, 2009
Residential New HVAC	September 1, 2008	
Residential Low Income	September 1, 2008	July 30, 2009
Residential Home Energy Performance	October 31, 2008	

Note 1: AmerenUE decided not to offer a program of this nature, as explained in its August 28, 2009 filing in Case No. ET-2007-0459.

Of the fifteen demand-side programs in AmerenUE's Electric Resource Planning filing on February 5, 2008, only eight have been implemented and all eight were implemented later than designated in the implementation plan by from 5 months to 10 months. Of the seven demand-side programs in the AmerenUE resource plan which have not yet been implemented, respective program implementation is between 9 and 14 months later than designated in the implementation plan.

AmerenUE has introduced one program during the test year in this case - twelve months ended March 31, 2009 - which was not included in the list of Electric Resource Planning preferred programs or planned pilot demand-side programs. The "Personal Energy Manager Rebate Pilot" ("PEM Pilot") became effective on August 6, 2009. The PEM pilot is a residential demand response program available only to Ameren Corporation employees. A participant will be issued a bill credit if the participant can get his/her energy usage below a certain amount during a Company-called event. Participants also receive an "in-home display" electronic device to let the participant know his/her current energy consumption and a "smart thermostat." According to the tariff sheet, evaluation of the pilot is due to be completed three months after the pilot's expiration date of October 31, 2009 (i.e., by January 31, 2010).

Staff Expert/Witness: Adam C. McKinnie

2. Costs Included In The Calculation Of Revenue Requirement

In a previous AmerenUE's rate case, Case No. ER-2007-0002, the Commission, by its *Order Approving Tier I Partial Stipulation and Agreement Filed on March 15, 2007*, issued April 11, 2007, approved a stipulation and agreement that resolved certain issues in that case. That stipulation and agreement was referred to as the "Tier I Agreement" in that case and, for convenience is so referenced here. The Tier I Agreement, among other things, provided "Treatment of Demand Side Management Costs proposed in the Direct Testimony of Staff witness Lena M. Mantle shall be adopted." Her direct testimony was marked as Exhibit 219 and filed in Case No. ER-2007-0002 on April 20, 2007.

In her direct testimony, filed in Case No. ER-2007-0002, Staff witness Lena M. Mantle proposed

> that demand-side costs that were incurred [by AmerenUE] in the test year not in the context of the collaborative process resulting from Case No. EC-2002-1, be placed in a regulatory asset account, assuming Commission approval of this methodology. AmerenUE would amortize the costs over a ten-(10-) year period. AmerenUE would be allowed to place the demand-side costs for each year subsequent to the test year in this case in the regulatory account. The amounts accumulated in this regulatory asset account should be allowed by the Commission to earn a return not greater than AmerenUE's AFUDC rate.

Thus, the Tier I Agreement provided for the creation of a regulatory asset account for expenditures by AmerenUE on programs for Demand Side Management (DSM). These DSM expenditures by AmerenUE could include expenditures for identifying, developing, screening, implementing, and evaluating energy efficiency and demand response programs. The regulatory asset account allows AmerenUE to treat the DSM expenditures on energy efficiency as a depreciable asset. In AmerenUE's last rate case, Case No. ER-2008-0318, one tenth of the amount AmerenUE spent through September 30, 2008 was included in the cost of service through a 10-year amortization. In this case the Staff has included in its development of AmerenUE's revenue requirement presented here, one tenth of the actual amount spent by the Company as the annual amortization expense associated with DSM programs. In addition, the Staff has included the actual amount spent by the Company on DSM programs in AmerenUE's rate base. The Staff will re-examine AmerenUE's DSM costs, including any adjustments as discussed below, as part of its true-up through January 31, 2010.

Staff Expert/Witness: Stephen M. Rackers

3. Residential Lighting And Appliance Program

Staff has concerns about the prudence and performance of Residential Lighting and Appliance Program (L&A) (Original Tariff Sheet Nos. 239-241) and recommends that the cost of the L&A be left in the regulatory asset and not included in AmerenUE's cost of service for setting rates in this case. Staff's concerns for the L&A were first raised in Case No. ET-2009-0404 in the form of *Staff Recommendation to Approve Tariff Sheets If AmerenUE Accepts Condition*, which is attached as Schedule JAR-1, within Appendix 3. Staff has always believed this market transformation program to be very risky, primarily because the program's design had never been implemented by a single utility that operates in a portion of a state, rather than the program being available throughout an entire state or a region of the country, and because the program's performance would be very difficult to measure.

The tariff sheets for this program are effective through September 30, 2011 and will terminate thereafter unless extended. In the implementation plan in AmerenUE's last electric resource plan filing (Case No. EO-2007-0409), the L&A had a three-year budget of $12.4 million and had a launch window of August to November 2008. AmerenUE did not file its tariff sheets for the L&A until March 25, 2009. The tariff sheets had an effective date of May 22, 2009.

AmerenUE contracted with Lockheed-Martin as its administrator for this program and all of other residential demand-side programs, but in September 2009 dismissed Lockheed-Martin as contractor for residential programs. With only 21 months remaining in the term of the program, AmerenUE has not provided Staff with any meaningful quarterly progress reports for the L&A. Such quarterly progress reports are a condition of the Commission's Order Approving

Tariff in Case No. ET-2009-0404. Very recently, AmerenUE advised Staff that: 1) Applied Proactive Technologies, Inc. as the new L&A administrator, 2) some program design changes are being made within the current tariff, and 3) the L&A budget is now $9.3 million.

At this time Staff does not have the information that it needs to determine whether or not the costs for this program were prudently spent. Staff recommends that the L&A program expenses remain in the regulatory asset, pending Staff's review of the L&A program evaluation and measurement of results, which are just beginning but should take two to three years to be relevant for purposes of determining whether AmerenUE should recover these costs.

Staff Expert/Witness: John A. Rogers

4. Demand-Side Programs Cost Recovery Mechanisms

With the passage of the "Missouri Energy Efficiency Investment Act" (also known as Senate Bill 376) by the 2009 Missouri Legislature, and subsequent signing by the Governor to become law on August 28, 2009, the State of Missouri has declared and directed as follows:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program

> or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.

Subsections 393.1075.3 and .4, RSMo. Supp. 2009.

While the Staff does not view AmerenUE's existing programs presently to be "demand-side programs proposed pursuant to this section [section 393.1075 RSMo. Supp. 2009]," the state policy of "valu[ing] demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs" should now guide the treatment of AmerenUE's existing programs. As the Staff interprets the foregoing statutory language, on the advice of counsel, "valu[ing] demand-side investments equal to traditional investments in supply and delivery infrastructure" is directed towards determining which resource to use. In contrast, cost recovery for demand-side programs is governed by the language, "allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs."

The Missouri Energy Efficiency Investment Act includes a list of mechanisms available to the Commission to implement the stated purpose of that Act, follows:

> 5. To comply with this section the commission may develop cost recovery mechanisms to further encourage investments in demand-side programs including, in combination and without limitation: capitalization of investments in and expenditures for demand-side programs, rate design modifications, accelerated depreciation on demand-side investments, and allowing the utility to retain a portion of the net benefits of a demand-side program for its shareholders.

Section 393.1075.5, RSMo. Supp. 2009.

The Staff has begun discussions with stakeholders regarding the intent of the Missouri Energy Efficiency Investment Act and the Staff plans to develop policies and rules to implement the Missouri Energy Efficiency Investment Act as soon as it gets revisions of the Chapter 22 rules to the Commission. The Staff proposes that AmerenUE continue the current regulatory asset treatment of demand-side costs as discussed in the Customer Demand-Side Programs Regulatory Asset section of this Staff Report until the Commission has established policies and rules to implement the Missouri Energy Efficiency Investment Act.

The Staff is aware that in the prefiled direct testimony of AmerenUE witness Stephen Kidwell AmerenUE proposes a demand-side management (DSM) cost recovery mechanism or tracker described as follows:

> … the full amount of the regulatory asset as of February 28, 2010 would be included in base rates, plus the average of incremental budgeted amounts for 2010 and 2011. The tracker would accumulate the difference between the amount in rates and the actual amount spent on DSM programs. At the Company's next rate case, AmerenUE would recover (or refund) any amounts in the tracker through a three year amortization of the balance, with interest.

Mr. Kidwell also discusses the need to include incentive mechanisms and lost revenues as a part of the proposed DSM tracker but in his direct testimony offers only the following aspects of AmerenUE's proposal:

> While these are very important considerations in designing an effective cost recovery mechanism for demand-side programs, AnerenUE is still in the very early stages of implementing its programs. We need additional experience and dialogue with stakeholders before we can adopt a definitive position on these issues.

In Mr. Kidwell's testimony AmerenUE proposes the following concerning resolution of the issue of cost recovery for demand-side programs:

> …to engage the other parties to this case in hopes of achieving a consensus solution. AmerenUE is working to schedule meetings with the Staff, OPC and other parties in this case, likely one in August and two in September, for the purpose of working through these issues. AmerenUE will subsequently provide a report to the Commission on these conferences, after receiving the benefit of input from the parties.

At the first of these meetings, AmerenUE told the parties that were present that it considered the meetings to be settlement discussions. The Staff and other stakeholders participated with AmerenUE in all-day settlement discussions held on September 17, October 8, October 30 and November 24 of 2009.

AmerenUE, Staff and the other stakeholders agreed, at the November 24, 2009 settlement discussion, to continue to explore and consider DSM cost recovery mechanisms, and have scheduled another telephone conference for December 22, 2009.

While AmerenUE's proposal is a starting point for discussion, many details of its proposal need to be clarified or determined. For example, Mr. Kidwell does not explain when costs would be placed into the DSM tracker that he proposes in his testimony. By statute the Legislature has stated that the Commission shall "[p]rovide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings." The resource planning process models demand-side programs that, with inputs selected by the planners, model to be cost-effective. The determination of whether or not a program is cost-effective and efficiency savings have been achieved cannot be made until after the program has both been implemented and evaluated post implementation. This analysis of DSM programs is analogous to how the addition of combustion turbines is analyzed. A utility is not allowed immediate cost recovery when it starts building a combustion turbine, even if doing so is shown to be the most cost-effective resource to meet a utility's needs. The utility must both build the combustion turbine and show that it works before the utility can recover the cost of the combustion turbine from its ratepayers. In the same way, the Missouri Energy Efficiency Investment Act requires that a DSM program be shown to be cost-effective and achieve verifiable efficiency savings before the cost of the program may be recovered from ratepayers. There just is not enough information in Mr. Kidwell's testimony to determine if it is consistent with the Missouri Energy Efficiency Investment Act.

Despite the settlement discussions, Staff, at this time cannot support the DSM cost recovery mechanism AmerenUE has proposed in the prefiled testimony of Mr. Kidwell.

Staff Expert/Witness: John A. Rogers

F. FAS 87 – Pensions and FAS 106 OPEB Trackers

See the discussion of these items in Section VIII.E.5., FAS 87/Pension Expense and Section VIII.E.6, FAS 106/OPEBs Expense.

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 2008 – March 2009) of AmerenUE'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. The Staff adjusted expenses to include interest calculated on the level of customer deposits reflected on Staff Accounting Schedule 10.

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 2008 – March 2009).

Staff Expert/Witness: Lisa M. Ferguson

I. Deferred Income Taxes

AmerenUE's deferred tax reserve represents, in effect, a prepayment of income taxes by AmerenUE's customers prior to payment by the Company. As an example, because AmerenUE is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense 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, AmerenUE'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.

Staff Expert/Witness: Stephen M. Rackers

VII. Allocations

A. Jurisdictional Allocations

Jurisdictional allocation factors are used to allocate demand-related and energy-related costs to the applicable jurisdictions. In this case, demand-related and energy-related costs are divided among two jurisdictions: retail operations and wholesale operations. The particular allocation factor applied is dependent upon the types of costs to be allocated.

Staff, as did AmerenUE, is utilizing a Twelve Coincident Peak (12 CP) methodology to determine demand allocation factors for AmerenUE. However, as is described in the Rate Revenue section VII.A.3., the allocation factors were calculated based upon the modified year. Staff has calculated the following demand allocation factors:

Retail Operations:	0.9547
Wholesale Operations:	0.0453

The energy allocation factor, for each individual jurisdiction, is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction to the total normalized AmerenUE 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 energy allocation factors for the particular jurisdictions, utilizing the modified twelve month period ending July 2009 as previously noted:

Retail Operations:	0.9456
Wholesale Operations:	0.0544

Staff witness Alan J. Bax provided these jurisdictional allocation factors to Staff witness Stephen M. Rackers.

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 AmerenUE. In this audit, the Staff reviewed the methods used by AMS to assign and allocate its costs to AmerenUE electric operations. Under the corporate cost allocation system employed by AMS, costs are either directly assigned to business units, directly allocated, indirectly allocated by function, or indirectly allocated from corporate to the business units. The direct assignment and allocation of costs, and the methods used to allocate costs from AMS, are provided in AmerenUE's cost allocation manual (CAM).

AMS determines the allocation factors annually, unless there is a significant change in circumstances. Beginning in January 2009, the allocation factor from AMS to AmerenUE's electric operations business unit increased due to the shifting of several AMS employees to other affiliates, however, the amount of AMS cost assigned to AmerenUE's electric operations did not appear to change significantly because there was less AMS cost to allocate in total. During September through November 2009, Ameren implemented two programs that eliminated positions from some of its subsidiaries. These programs may have impacted the allocation of AMS costs to AmerenUE's electric operations. The Staff will need to examine the allocation of AMS costs to AmerenUE's electric operations through the true-up period ending January 31, 2010. Based upon this true-up examination, the Staff may need to perform adjustments to address any significant changes in the allocation of AMS costs to AmerenUE's electric operations on a going forward basis.

Staff Expert/Witness: John P. Cassidy

VIII. Income Statement

A. Rate Revenues

1. Introduction

Since the largest component of operating revenues result from rates charged AmerenUE's Missouri 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 AmerenUE 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 AmerenUE's charges for providing electric service to its Missouri retail customers (native load). AmerenUE'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 FAC are not included.

Revenue from Off-System Sales: Revenue from off-system sales is realized as a result of AmerenUE selling electricity to other utilities at non-regulated prices. The gross revenues from theses sales, less the generation or purchased power expense AmerenUE 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 electric facilities 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 present Staff's annualized, normalized customer electricity usage and revenues by rate class for AmerenUE's electrical operations.

The intent of the Staff's adjustments to customer usage and rate revenues is to determine the level of revenues that AmerenUE would have collected on an annual, normal-weather basis, based on information “known and measurable” at the end of the time period. However, here, because of a trend it observed in customer usage and the availability of data through July 31, 2009, the Staff has used customer usage data known and measurable as of July 31, 2009, rather than at the end of the test year, March 31, 2009. This 12-month period ending July 31, 2009, is referred to in this report as the "modified year".

The two major categories of revenue adjustments are known as “normalizations” and “annualizations.” Normalizations deal with events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect. Adjusting to normal weather is an example of a normalization adjustment. Annualizations are adjustments that re-state results as if conditions known at the end of the time period had existed throughout the entire time period. Adjusting for customer growth, i.e., making adjustments to reflect the customers on the system at the end of the time period as if they were on the system the entire time period, is an example of an annualization adjustment.

In rate cases, revenue normalization always starts with a review of usage data such as daily load research and net system input data. While reviewing AmerenUE’s daily load research and net system input data for the 12 months ending March 2009, the Staff discerned an unanticipated trend. The average daily load for the Spring of 2009 trended lower and appeared possibly less responsive to weather than the average daily load for the spring of 2008. This led to further Staff analysis of the Net System Input average daily load through July 31, 2009. This further analysis confirmed that the trend of lower average daily load for the spring of 2009 than in 2008. Furthermore, this trend continued through July 31, 2009.

The Staff considered the following methods of capturing the observed lower usage for purposes of its direct filing in this case:

1. Normalize the test year usage data and ignore the trend. This approach would be based on an assumption that the difference is due only to the number of customers, and not the per customer electricity use;

2. Normalize the test year usage data, adjust the test year usage data for the lower usage seen in the summer of 2009 and then make another adjustment for growth through the true-up cut-off date of January 31, 2010. This approach would be based on an assumption that an accurate estimated adjustment to electricity usage per customer could be made; or

3. Normalize usage data for the twelve months ending July 31, 2009, and determine growth (positive or negative) based on the number of customers at the end of March 2009. This approach would incorporate changes in the usage vs. temperature relationship for the period of April 1, 2009, through July 31, 2009, presumably reducing the adjustment for the true-up cut-off of January 31, 2010.

After careful deliberation, the Staff chose the third option of normalizing data for the twelve months ending July 31, 2009. The Staff normalized class revenues, determined net system input for the fuel model, and calculated the energy and demand allocation factors using the data for this 12-month period. In determining growth, Staff applied the number of customers as of March 31, 2009 to the usage during the period August 1, 2008 to July 31, 2009. Before electing this option the Staff explained to the other parties, including AmerenUE, why it was planning to choose this option, and no party objected or raised any concern. This 12-month period ending July 31, 2009, is referred to in this report as the "modified year".

Staff Expert/Witness: Lena M. Mantle

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Adjustment to Remove Unbilled Revenues

The recording of unbilled revenue on the books of the Company is an attempt to recognize the 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 unnecessary to recognize unbilled revenue. Therefore, Staff has removed unbilled revenue from its determination of revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

b. Adjustment to Remove Gross Receipts Tax (GRT)

The Company acts as a collector for taxes imposed on utility service revenues by municipalities and other taxing jurisdictions. The GRT included on a customer's bill is collected by the Company which, in turn, remits the collections 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 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 through an adjustment and the GRT recorded in expense through a companion adjustment assures that GRT will have no impact on net income or revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

c. Preliminary Adjustments to Test Year

Starting with revenues based on Revenue Month (the month in which sales and revenues were reported in AmerenUE's billing system), Staff adjusted AmerenUE's rate class revenues as required to reclassify revenues to Primary/Rate Month (the month reflecting the rates and revenues when service actually occurred). The total annual preliminary adjustment to modified year revenues is an increase in revenues of $877,563.

Staff Expert/Witness: Curt Wells
Staff Expert/Witness: Manisha Lakhanpal

d. Update Period Adjustment

As explained above, analysis of AmerenUE data showed that net system input (NSI) and, consequently, usage in 2009 differs significantly from the corresponding months of 2008. To provide a more current basis for normalization, annualization, and growth calculations, sales data used to determine revenues in this case were based on the 12-month period ending July 31, 2009.

Staff Expert/Witness: Curt Wells
Staff Expert/Witness: Manisha Lakhanpal

e. Billing Adjustments

Significant overbillings to AmerenUE's retail customers occurred in August 2008 in the Residential (RES), Small General Service (SGS), Large General Service (LGS), and Small Primary Service (SPS) rate classes as a result of Ameren's initial implementation of an Automated Meter Reading (AMR) system. Staff reduced usage and revenues to correct these errors and to correct other small billing errors. These billing adjustments in total reduced revenues by $15,834,562.

Staff Expert/Witness: Curt Wells

f. Large Customer Annualization

Large Power Service rate class - The adjustments are based upon the period of August 1, 2008 through July 31, 2009, and will be updated for known and measurable changes through the true-up period January 31, 2010. There were 72 customers in the Large Primary Service (LPS) rate class during this period. A data check was done for billing corrections prior to making adjustments. The Staff annualized LPS customers on an individual customer (account) basis. The Staff graphically examined each LPS customer's monthly demand and energy use, over multiple years, through July 31, 2009, to determine if an adjustment was needed, and if so, what adjustment was needed.

The general intent of an annualization is to re-state kWh results for the 12 months being examined as if conditions known at the end of the 12-month period had existed throughout the entire 12-month period. Both because they are a significant part of a utility's total load and they are relatively few in number, it is customary for Staff to annualize each of the very largest customers to reflect any major growth or decline in kWh usage and rate revenues in the 12-month period due to the addition of new customers, the loss of existing customers, and load growth or decline of specific existing customers. As part of load annualization three (3) LPS customers were load adjusted because AmerenUE expects those customers to change their future load and energy consumption. The load that seemed incongruous was replaced by average numbers from following months when that load seemed to better represent the future ongoing consumption of the customer. The total annualization for load change to modified year revenues attributable to the LPS customers is a reduction in revenues by $4,780,926. This was partially offset by one new customer who joined the LPS rate class and whose total annualized revenue resulted in an increase in revenues of $200,232. The resulting total annualization for these two adjustments was a reduction of $4,580,694.

Large Transmission Service rate class - There is only one customer being served under AmerenUE's Large Transmission Service (LTS) rates, and its electric consumption was significantly reduced earlier this year due to an ice storm that caused a power outage at that customer's facility. The customer has been operating at reduced loads during the modified year and beyond; however, based on information regarding the customer's planned future electric consumption, Staff has annualized that customer's load as it existed during calendar year 2008 when that customer's facility was operating at full capacity (load). Since 2008 calendar year was a leap year, the customer's February 2008 consumption was adjusted to account for the extra day. The rate change annualization for LTS rate class is an increase in revenues of $4,551,016.

Staff Expert/Witness: Manisha Lakhanpal

g. Annualization for Rate Switching

During the modified year, four (4) customers switched from the SPS Time of Use rate class to the LPS rate class. The Staff made an annualization adjustment by moving each customer's modified year usage data for the affected months from the SPS class data to the LPS class data.

For the customers who switched rate classes during this period the annualization adjustment to revenues of the modified year is a reduction to revenues of $185,919.

Staff Expert/Witness: Curt Wells
Staff Expert/Witness: Manisha Lakhanpal

h. Annualization for Rate Change

Actual rate revenues from the 12 months ended July 31, 2009, do not reflect any of the changes to AmerenUE's rates made on March 1, 2009 as a result of Case No. ER-2008-0318. Thus, these revenues are understated by the difference between the amounts that were actually billed to customers during the 12 months ended July 31, 2009, and the amounts that AmerenUE would have been billed to customers if the current rates (effective March 1, 2009) had been in effect throughout the entire period. The Staff's method of computing annualized revenues for each rate class for this rate change is to multiply updated billing units for the 12 months ended July 31, 2009 period by current rates. The difference between these computed annualized revenues and the amounts billed by the Company during this period under the prior rates is the rate change adjustment. The total annualization for rate change to revenues is an increase to revenues of $100,281,115

Staff Witness for LPS and LTS classes: Manisha Lakhanpal
Staff Witness for all other classes: Curt Wells

i. Weather Normal Variables

The actual weather experienced during any year is unique and unlikely to be repeated exactly when the new rates from this case are in effect. Since each year's weather is unique, modified year sales need to be adjusted to "normal" weather. In this case Staff's adjustments to Sales and Revenue are based on the period August 1, 2008 through July, 31, 2009. NOAA[14] 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 Climate Center's (MRCC) database for St Louis Lambert International Airport weather station. The Staff and AmerenUE agreed to these adjustments to the actual daily temperatures in Case No. EM-96-149.

The data required to weather normalize sales are 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 to bring forward the previous day's residual effect on usage in the current day.

Normal weather ranking - For this case, the Staff and AmerenUE used the same methodology. The Staff uses normal weather temperatures 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 temperature extremes. The daily temperature normals are calculated by averaging the ranked temperatures in each year of the 30-year normals period,

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[14] National Oceanic and Atmospheric Administration.

irrespective of the calendar date. This results in the normal extreme temperature 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,[15] these normal temperatures are then assigned to the days of the modified year based on the rankings of the actual temperatures of the modified year.

This information was provided to Staff witness Walt Cecil for weather normalization of customer usage and to Staff witness Shawn E. Lange for weather normalization of net system input.

Staff Expert/Witness: Manisha Lakhanpal

j. Weather Normalization of Usage

Electricity consumption is highly responsive to the weather, specifically temperature. As the outside temperature increases, reaching higher levels, the demand for cooling, air conditioning and fans, pushes the consumption of electricity to a maximum. As the weather becomes cold and temperature falls, the demand for additional heating, electric space heating for example, also forces an increase in electricity consumption. Electric air conditioning and space heating are both prevalent in AmerenUE's service territory; therefore, AmerenUE's electric load is correlated with and responsive to temperature.

Temperatures in AmerenUE's service territory were cooler than normal during the months of August and September 2008, and June and July 2009, which resulted in electric energy sales lower than those expected under normal weather conditions. Temperatures in AmerenUE's service territory were warmer than normal during the months of December 2008, and January through March 2009, which also resulted in lower electric energy sales than those expected under normal weather conditions. Since the temperatures in the modified year used by Staff deviated from normal and since Staff chose a more recent modified year to review than the one used by AmerenUE, Staff performed its own weather impact analysis. However, the method and model used by Staff are similar to those used by AmerenUE.

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15 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.

Staff's model 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; the incorporation of different base usage parameters to account for different days of the week, months of the year and holidays; and, elements to correct for seasonal variations in the data. As a check, the resulting weather adjustments were compared to the weather-normalized, independent net system input (described in the *Weather Normalization of Net System Input* section of this report). Comparisons of the magnitude and direction of the weather adjustments of the classes' usages were made to the magnitude and direction of changes in the weather-normalized net system input. Based upon these comparisons, the results of the Staff's methodology and model were determined to be reasonable and were provided to Staff witness Curt Wells to be used in the normalization of revenues for the RES, SGS, LGS, and SPS rate classes.

The Staff did not weather normalize the LPS class usage. This class is heterogeneous in nature; therefore, the Staff annualizes the LPS class usage for changes in customer usage as well as in changes in the customers taking that service during the modified year. Please see *Large Power Annualization* by Staff witness Manisha Lakhanpal above for an explanation of the annualization procedure. Those conditions that led the Staff to use data from the modified year were pronounced and affected each of the members of the LPS class differently; therefore, the Staff annualized the usage data of those members of the class, as deemed appropriate. Further, the Staff reviewed AmerenUE's weather normalization analysis of the LPS and found AmerenUE's overall estimated kWh weather adjustment for the test year was minimal (approximately 0.024%). Therefore, the Staff did not weather normalize LPS usage or revenues.

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

k. Weather Normalization of Usage and Revenue

The Staff weather normalized modified year usage data AmerenUE provided for the RES, SGS, LGS, and SPS rate classes by applying weather normalization factors Staff witness Walt Cecil provided for each class for each month. The modified year billing units were adjusted by these normalization factors and AmerenUE's current rates were applied to determine weather-normalized revenues. The differences between these class weather-normalized revenues and the modified year revenues, as adjusted above, determined the amount of the weather normalization adjustments to revenues. The total annual weather normalization of modified year revenues is a reduction to revenues of $1,174,325.

Staff Expert/Witness: Curt Wells

l. "Days" Adjustment

Since billing months are an aggregation of bill cycles, they cover a different time period than calendar months. To account for this difference, the Staff calculated a "days" adjustment for each weather sensitive class to adjust the level of annual weather-normalized billing month kWh usage to coincide with the annual, weather-normalized, calendar month kWh usage. The Staff calculated the "days" adjustment for each rate class that was weather normalized by taking the difference between the weather-normalized calendar month usage over the modified year, and the weather-normalized revenue month usage over the same period. Revenues for the weather sensitive classes were adjusted by allocating the "days" adjustment proportionately to the appropriate monthly kWh usage for each class and then applying current rates. The difference between the revenues calculated in this way for each class and the modified year revenues for the class determined the "days" adjustment for that class.

For the LPS and LTS classes, rate revenues and kWh usage are 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.

"Days" adjustments are also known as adjustments to "unbilled" sales and "unbilled" revenues on financial statements. The total annual "days" adjustment of modified year revenues is a reduction of $4,920,036.

Staff Witness for LPS and LTS classes: Manisha Lakhanpal
Staff Witness for all other classes: Curt Wells

m. Customer Growth Annualization

The Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional, and in certain cases, reduction in kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of the test year (March 31, 2009) had existed 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 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 test year levels. These classes include RES Time-of-Use, SGS Time-of-Use, SGS Unmetered, LGS Time-of-Use, SPS Time-of-Use, LPS, Outdoor Lighting and LTS.

Staff Expert/Witness: Kofi Agyenim Boateng

n. 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

o. Removal of Rate Refunds

Staff has made an adjustment to remove the provision for rate refunds recorded by the AmerenUE during the test year. This amount represents the first month's operation of the Company's Fuel Adjustment Clause (FAC). This item relates to prior period revenues and is, therefore, appropriately eliminated from the revenue requirement computation in this case.

Staff Expert/Witness: Kofi Agyenim Boateng

B. Off-System Sales and Transmission Revenue

1. Off-System Sales (OSS)

a. Energy

Off-system sales are those sales of electricity made after AmerenUE 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 off-system sales, AmerenUE generates profits or net margin, which represents total proceeds from the sales less associated generation or purchased power cost. It is appropriate to include off-system sales in the cost of service because AmerenUE'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 off-system sales are made using these facilities, as well as by purchasing power, the customers should benefit from these sales. Off-system sales represent an efficient utilization of the electric facilities/system that has been put in place to meet the electricity needs of AmerenUE's customers.

Off-system sales 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 off-system sales revenue represents the inclusion of additional revenue in order to annualize the off-system sales revenues that were calculated by Staff witness David W. Elliott using the RealTime™ production cost model. This was recorded in the Staff's revenue requirement cost of service calculation by subtracting AmerenUE's test year ending March 31, 2009, per book off-system sales revenues from the Staff's annualized level of off-system sales revenues as determined by the production cost model using Staff's hourly market energy prices The Staff will continue to examine off-system sales revenues through January 31, 2010, which represents the true-up cutoff date as approved by the Commission as part of this rate proceeding.

Staff Expert/Witness: Roberta A. Grissum

b. Capacity Sales

When unneeded to serve its own load, AmerenUE is able to sell capacity to other utility companies. The Staff included an adjusted level of capacity sales that are contracted through January 2010, as of June 2009. This level of sales incorporates the expiration of the purchased power contract with Arkansas Power & Light Company. It also reflects the return of Noranda Aluminum, AmerenUE's largest customer, to full load. In addition, capacity sales associated with Taum Sauk have been included in the cost of service as though this unit was available for service. The staff will re-examine the level of capacity sales as part of its true-up audit.

Staff Expert/Witness: Roberta A. Grissum

2. Energy and Capacity Contracts

AmerenUE entered into two capacity and energy contracts since the true up date in AmerenUE's last rate case (Case No. ER-2008-0318): a 12-month contract with an electric utility (American Electric Power Company) and an 18-month contract with an electric cooperative (Wabash Valley Power Cooperative). Staff's treatment of these contracts as wholesale contracts in this case does not reflect a change in how Staff generally treats such contracts and is not an acceptance of the definition of wholesale contract AmerenUE used for its direct filing in this case. These contracts were excluded from the off-system sales revenue calculations as required in AmerenUE's FAC due to the length of the contract (long term full and partial requirement sales are excluded from the off-system sales revenue calculations) and, therefore, these contracts are considered to be contracts with wholesale customers for purposes of AmerenUE's FAC. While treated in this manner for purposes of AmerenUE's FAC, designating contracts with other utilities and electric cooperatives as wholesale customer contracts is not how these types of contracts have been traditionally treated in Missouri when setting rates. Instead, when setting general electric rates, sales to municipals are treated as wholesale sales and sales to other utilities and electric cooperatives as are treated as off-system sales. The language in AmerenUE's FAC was neither intended nor designed to change the definition of an off-system sale used for purposes of setting general electric rates.

Staff Witness: Lena M. Mantle

3. MISO Day 2

a. Revenues

AmerenUE 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 Market"). 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

AmerenUE's offer price. When the Company's total offer prices are not covered by the market prices, AmerenUE receives RSG payments. For AmerenUE, the RSG payments received from MISO during the test year totaled $6,066,928.

The RSG payments are funded by billings to market participants based on their loads. Thus, AmerenUE 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 AmerenUE'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, AmerenUE 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 AmerenUE. If the RSG payments only covered cost, then there would be no profit received by AmerenUE 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 AmerenUE 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. Based on AmerenUE's response to Data Request No. MIEC 1-12 and other related workpapers, Staff has removed about 61% of the test year RSG revenues as an assumed level of cost recovery.

b. Amortization of Revenue Sufficiency Guarantee (RSG) Resettlement Expenses

Consistent with the Commission's Report & Order in the last Union Electric Company rate case, Case No. ER-2008-0318, relating to MISO resettlement charges, the Staff has included an amortization of the RSG Resettlement. However, the amount of the Staff's amortization, $2,039,832, reflects a 2-year amortization of the remaining balance (unamortized portion) of the RSG resettlement cost as of the end of June 2010, the effective date of rates in the current case. The Staff is proposing a 2-year amortization period in order to better synchronize the end of the amortization with future rate case recovery.

Staff Expert/Witness: Kofi Agyenim Boateng

4. 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. The Staff is also recommending an adjustment to the level of test year MISO transmission expense to eliminate the expenses that are non-recurring.

Staff Expert/Witness: Kofi Agyenim Boateng

5. Ancillary Services Market (ASM) Revenue and Expense

AmerenUE also participates in MISO's "Day-3" market which has real time and day-ahead energy markets and an Ancillary Services Market (ASM). AmerenUE 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, which means that the test year of April 1, 2008 through March 31, 2009 per books does not reflect a full year of the additional revenues and expenses. The Staff has annualized ASM revenues and expenses by using the actual revenues and expenses for January 2009 through May 2009, and AmerenUE's projected data for June through December 2009. The Staff will continue to review AmerenUE'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 its Report and Order issued in Case No. ER-2007-0002, the Commission established an accounting mechanism to track AmerenUE'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 variations from the terms of the contacts through which AmerenUE purchases its coal supply. 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 AmerenUE's short-term borrowing rate. This SO_2 tracker was continued as part of Case No. ER-2008-0318.

As part of the previous rate proceeding, Case No. ER-2008-0318, the Company had a $8,534,159 SO_2 regulatory asset balance at September 30, 2008, that was to be amortized over a period of two years (or $4,267,080 annually). The Company recorded one month of this amortization, or $355,590, during the test year ending March 31, 2009 that was established by this Commission in the current rate proceeding. Therefore the Staff has included an additional $3,911,490 in the cost of service calculation to annualize this portion of the SO_2 tracker amortization. For all activities that occurred during the period of October 2008 through March 31, 2009 the Company's SO_2 tracker balance represented a regulatory asset of $5,213,000. Therefore the Staff included an additional $2,607,671 to reflect a two year amortization for this balance. In total the Staff has included an additional $6,518,161 of expense in the cost of service calculation to annualize the amortization expense associated with the SO_2 tracker.

On a going forward basis the Staff recommends that the SO_2 tracker be discontinued. In the future, the cost associated with the SO_2 premiums, net of discounts, will be collected through AmerenUE's Fuel Adjustment Clause and the revenues from gains on the sale of SO_2 emission allowances will flow through the proposed Environmental Cost Recovery Mechanism.

Staff Expert/Witness: Roberta A. Grissum

D. Fuel and Purchased Power Expense

The Staff's annualized and normalized fuel and purchased-power expense is sufficient to serve native load and make off-system sales. The 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 January 31, 2010. Staff's fuel expense adjustment for nuclear fuel is based upon an 11-month average price for the period ending September 2009 provided by Company in its response to Staff Data Request No. 65. The Staff's fuel expense annualization also incorporates a three-year average of natural gas through July 31, 2009 and a three year average of fuel oil commodity prices through October 31, 2009 as sponsored by Staff witness Erin L. Maloney. The Staff also included in the fuel cost calculation the fixed demand cost of natural gas and a reduction resulting from fly ash activities. The Staff's annualized purchased power expense levels reflect the impact of forecasting error, contractual purchased power energy prices as well as a three-year average of spot market energy prices as sponsored by Staff witness Erin Maloney.

1. Fuel and Purchased-Power Prices

The Staff reviewed all of AmerenUE's coal commodity and coal transportation contracts. The Staff reviewed nuclear, natural gas and fuel oil prices as reflected in Company fuel reports, workpapers and responses to Staff data requests. The Staff reviewed purchased power energy prices associated with the Company's long-term, purchased power agreement with Pioneer Prairie Wind Farm LLC. Staff also reviewed three years of market energy prices. The Staff's fuel expense adjustments reflect all known increases in commodity coal and coal transportation costs that will be in effect as of January 31, 2010. The Staff's fuel expense adjustments also reflect actual known and measurable nuclear fuel prices through September 30, 2009. The Staff will continue to examine all of these fuel cost components through the true-up period ending January 31, 2010 in order to address any significant changes. The Staff's purchased power expense adjustments reflect the long-term purchased power agreement with Pioneer Prairie Wind Farm, as well as a three-year average of market energy prices through October 31, 2009.

a. Coal Prices

i. Accounting Coal Prices

The 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. The Staff performed a review of all of AmerenUE's current accounting coal commodity and coal transportation contracts. The Staff's accounting coal prices reflect AmerenUE's mine specific coal commodity and coal rail and barge transportation contracts that will be in effect as of January 31, 2010. The 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. The Staff included all railcar related costs as a component of the accounting coal price used in the production cost model. For purposes of this proceeding, Staff made an adjustment to remove all costs incurred during the test year associated with the fuel additive magnesium oxide, since AmerenUE has no plans to continue using this fuel additive at any of its coal units at any point during 2010 or thereafter. The Staff also included a normalization adjustment in the cost of service calculation to reflect a reduced level of expense associated with Company's use of the fuel additive Urea at one of its coal plants in comparison to what was incurred during the test year for this item.

Staff Expert/Witness: Roberta A. Grissum

ii. Dispatch Coal Prices

Consideration of coal dispatch prices is necessary in determining fuel and purchased-power expense because coal dispatch prices include environmental costs which need to be included in the decision regarding whether or not a plant should be dispatched. Therefore, dispatch costs are higher than the actual fuel cost. While the fuel cost of two different plants may be the same, the dispatch cost may be different depending on the environmental emissions equipment at the plant.

Coal dispatch prices for the various generating units were determined using a twelve-month average delivered coal price for each turbine provided per the 4 CSR 240-3.190(1)(C) monthly reporting requirement. To incorporate the latest data available, the twelve-month period ending October 2009 was used. Different AmerenUE turbines have different environmental costs. Average annual SO_2 and NOx costs were calculated for each of the turbines using the data provided from AmerenUE in response to Data Request No. 53. The SO_2 and NOx costs were added to the delivered coal price and the result is a coal dispatch price per generating unit or facility which was used in the production cost model to determine net fuel costs.

Staff Expert/Witness: Erin L. Maloney

b. Nuclear Fuel Prices

Staff used a 11-month average price based upon actual nuclear fuel prices for the period ending September 30, 2009 provided by Company in its response to Staff Data Request No. 65. The 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: Roberta A. Grissum

c. Natural Gas Prices

<u>i. Variable Natural Gas Cost</u>

The Staff analyzed natural gas prices over a three-year period using data provided in response to Staff Data Request No. 52. Staff calculated the average system price per month using the three years of monthly data ending July 31, 2009. Twelve (12) monthly gas prices were used as input to the production cost model.

Staff Expert/Witness: Erin L. Maloney

<u>ii. Fixed Natural Gas Cost</u>

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

Staff Expert/Witness: Roberta A. Grissum

d. Oil Prices

Fuel oil plays a very small part in the total fuel costs of AmerenUE. The fuel oil price was calculated as the 36-month average of the monthly average fuel oil prices provided per the

4 CSR 240-3.190(1) reporting requirements. The three year period ending October 31, 2009 was used. A single fuel oil price was used in the production cost model.

Staff Expert/Witness: Erin L. Maloney

e. Purchased Power Prices

The Staff analyzed three years of hourly power prices using the actual power transactions provided to the Staff per the 4 CSR 240-3.190(1) monthly reporting requirements for the period ending October 31, 2009. Staff removed the zero megawatt and zero dollar transactions as well as the Arkansas Power & Light Company long-term capacity contract transactions and developed an hourly average market price weighted by the actual sales and purchases made during that hour. Monthly averages of on- and off-peak prices for each month in the data set were calculated and averaged for each month of the year. The actual hourly prices that occurred in the twelve months ending July 31, 2009 were then adjusted to meet the 12 monthly on-peak and 12 monthly off-peak averages. The resulting 8,760 hourly prices were then used as input to the production cost model.

Staff Expert/Witness: Erin L. Maloney

f. Potential Refundable Entergy Charges

As part of the last rate proceeding, Case No. ER-2008-0318, AmerenUE 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.

As part of a former purchased power agreement with Entergy that expired in August 2009, AmerenUE made payments for pass-through equalization charges that it disputed. AmerenUE 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 in AmerenUE's last rate proceeding. In addition all legal costs that AmerenUE incurred to address this matter were also included in AmerenUE's rates as part of the last rate proceeding. All legal costs to deal with this ongoing matter that were incurred during the test year in the current rate proceeding are included in the Staff's cost of service calculation. Because these costs have been included in the determination of rates for AmerenUE in the previous rate proceeding and are therefore being paid for by AmerenUE ratepayers, it is appropriate for those ratepayers to benefit from any future refunds that may occur for these costs. To date AmerenUE 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 January 31, 2010 to determine if additional adjustments will be necessary to address any refunds. If no refunds are received by AmerenUE through the end of true-up in the current rate proceeding, the Staff will address this issue as part of AmerenUE's next general rate proceeding.

Staff Expert/Witness: Roberta A. Grissum

2. Production Cost Modeling

a. Variable Cost

The Staff estimates the variable fuel and purchased power expense for AmerenUE for the modified year, as defined in the Rate Revenue Section, ending July 31, 2009 to be $473,143,781 with off-system sales, and $635,413,837 without off-system sales.

The Staff used the RealTime® production cost model to perform an hour-by-hour chronological simulation of AmerenUE's generation and power purchases. The production cost model determines the annual variable cost of fuel and purchased power to economically match AmerenUE'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 AmerenUE witness Tim Finnell, and data AmerenUE supplied to comply with 4 CSR 240-3.190. The generating unit data included 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 AmerenUE's wind power contract with Horizon Pioneer Prairie was also an input to the model.

The Staff's model was benchmarked by using AmerenUE's model inputs. The difference between Staff's model benchmark results and the AmerenUE model results that support Tim Finnell's direct testimony was 0.21%.

For this rate case the Staff's 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 AmerenUE generating unit outages were normalized by averaging the six years of actual values taken from responses to data requests, and data AmerenUE supplied to comply with 4 CSR 240-3.190.

Staff Expert/Witness: David W. Elliott

3. 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. The hourly load information from AmerenUE for the modified year, as defined in the Rate Revenues section, was used rather than the test year period of the twelve months ended March 31, 2009. Due to reasons outlined by Staff witness Manisha Lakhanpal in ***Adjustments to Test Year Sales and Revenue***, the hourly loads of the Large Transmission Service class were removed from the NSI hourly loads before making any normalization or annualization adjustments. As an annualization adjustment, the load data of two wholesale customers that left AmerenUE's electric system during the test-year were removed, since the customers are not expected to cause load requirements on AmerenUE's system when new rates from this case go into effect.

Due to the presence of air conditioning and the presence of significant electric space heating in AmerenUE's service territory, the magnitude and shape of AmerenUE's net system input is directly related to daily temperatures. Actual and normal daily temperatures provided by Staff witness Manisha Lakhanpal 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 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 and to the peak loads 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."[16]

[16] 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

After weather normalizing the net system input, the annualized level of LTS hourly loads was added to the weather-normalized hourly NSI, as well as the annualized hourly loads for two additional wholesale customers.

After weather-normalizing and annualizing usage for AmerenUE's retail customer classes is completed, weather-normalized wholesale usage is added. Then the non-LTS class annual usage was increased by the average annual loss factor supplied by Staff witness Alan J. Bax. The LTS class' annual usage was increased by the losses used in calculating the revenues for that class. The loss adjusted annual LTS class usage was added to the loss adjusted non-LTS annual usage. The annualized usage for the two additional wholesale customers was increased for transmission losses and added to the loss adjusted non-LTS annual usage to produce an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with Staff's normalized revenues.

A factor was applied to each hour of the weather-normalized loads to produce an annual sum of the hourly net-system loads that equals the usage, plus losses, and 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 hours in developing the Staff's jurisdictional energy allocator.

Staff Expert/Witness: Shawn E. Lange

<u>4. Losses</u>

System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) of AmerenUE's system between its generating sources and the customers' meters. In addition, small, fractional amounts of energy either stolen (diversion) or not metered are included as system energy losses.

The basis for calculating system energy losses is that 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; 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%:

$$\text{System Energy Loss Percentage} = (\text{System Energy Losses} \div \text{NSI}) \times 100\%$$

NSI is also equal to the sum of the Company's net generation and net interchange. Net interchange is the difference between interchange purchases and off-system 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.

Staff has calculated a loss percentage on AmerenUE's system, for the twelve months ending March 2009, of 5.05% of NSI. This line 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

E. Payroll and Benefits

1. Payroll and Payroll Taxes

Staff's annualized payroll was based upon the test year ending March 31, 2009, actual Missouri electric related payroll expense adjusted for the following: a) normalization of overtime associated with the Callaway refueling, b) inclusion of the lump sum amortization applicable to union contract employees, c) increases in wage rates that have occurred since the true-up cutoff date in the Company's last rate case and d) the reduction of payroll expense that resulted 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 2009. The Staff describes the VSE and ISP programs in more detail in the next section of this Cost of Service Report.

After allocating a portion of 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, 2009. The Staff's Accounting Schedule 10, Adjustments to Income Statement, reflects approximately 77 adjustments in order to restate test year payroll expense to an annualized level.

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. Based on these calculations the Staff developed a corresponding $152,000 FICA payroll tax adjustment. The Staff also removed from the cost of service calculation approximately $32,000 for all Federal Unemployment Tax Act (FUTA) taxes paid during the test year for employees that are no longer with the Company.

2. Voluntary Separation Election (VSE) and Involuntary Separation Program (ISP)

Based upon the response to Staff Data Request No. 240, the Company has indicated that through November 19, 2009 ** ____ **. It is important to realize that while AmerenUE employees represent a direct assigned payroll cost while only 36.83% of AMS employee payroll costs were assigned to AmerenUE during the test year ending March 31, 2009.

During September 2009, Ameren offered a voluntary separation election (VSE) to management employees. Employees eligible to participate in the VSE must have been age 58 or older by December 31, 2009. ** ____ program. **

During November 2009, Ameren implemented an Involuntary Separation Program (ISP). **____

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Staff Expert/Witness: John P. Cassidy

3. Amortization of Severance Costs

On September 30, 2009, AmerenUE recorded an approximate ** ___________ ** accrual on its books to reflect its estimate of the severance costs that will be incurred as a result of the VSE and ISP programs. In order to provide the Company an opportunity to recover these extraordinary severance costs, the Staff included in the cost of service calculation an adjustment of ** ___________________________________ **. The Staff proposes to begin the amortization of these costs on the effective date that rates are established in this rate proceeding. As part of its true-up audit, the Staff plans to correct this amortization adjustment to be reflective of actual severance costs, once actual severance payments are finalized and are made available to the Staff for review.

4. Callaway Security Force

By January 2009, AmerenUE hired an in-house security force for its Callaway nuclear power plant. The Staff has included adjustments in the cost of service calculation, consistent with the Company, to reflect this change.

Staff Expert/Witness: John P. Cassidy

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5. FAS 87 Pension Costs

a. FAS 87 Pension Tracker

The Staff, AmerenUE and other parties entered into a Stipulation and Agreement (Agreement) in Case No. ER-2007-0002 that addresses the ratemaking treatment for annual pension cost under Financial Accounting Standard (FAS) 87. The Agreement requires AmerenUE to fund its annual FAS 87 pension expense and track the difference between the annual FAS 87 pension expense and the level included in rates. The difference between the annual FAS 87 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. Consistent with the Agreement from Case No. ER 2007-0002, the Staff's rate base for AmerenUE is reduced for a regulatory liability in the amount of $5,168,377 which represents the overcollection in rates of FAS 87 pension expense, compared to the actual expense incurred. This amount is the net of $4,295,736, which represents a regulatory asset in this current rate case and $9,464,113, which represents the unamortized portion of the regulatory liability in Case No. ER-2008-0318. Both of these amounts were calculated taking into consideration the estimated balances projected as of January 31, 2010, the end of the true-up period. The Staff has also included a reduction to pension expense in its income statement in the amount of $840,530, for the annual amortization, over five years, of the amount accumulated in the FAS 87 pension tracker.

b. Annualization

The Staff also annualized pension expense to reflect the 2009 FAS 87 cost provided by AmerenUE's actuary, Towers Perrin. This level will be the amount used in the pension tracker, after rates are established in this case, to determine the difference between FAS 87 expense included in rates and the amount actually incurred and funded by AmerenUE.

Additionally, Staff has adjusted the test year pension expense to account for the VSE and ISP which called for the elimination of certain management positions within AmerenUE and AMS. Staff expert witness John P. Cassidy discusses the VSE and ISP in detail under that section of this Cost of Service Report.

Since some of AmerenUE's management and administrative functions are provided by AMS employees, AmerenUE's pension expense includes costs that are allocated from AMS.

Staff Expert/Witness: Kofi Agyenim Boateng

6. FAS 106 Other Post Retirement Benefit Costs (OPEBs)

a. FAS 106 OPEBs Tracker

The Agreement in ER-2007-0002 also addresses the ratemaking treatment for the annual OPEBs cost under Financial Accounting Standard (FAS) 106. As with FAS 87, the Agreement requires funding of the annual FAS 106 expense and establishes a tracker for the difference between the amount of FAS 106 expense in rates and the actual expense incurred. Consistent with the Agreement from Case No. ER 2007-0002, the Staff's rate base for AmerenUE is reduced for a regulatory liability in the amount of $32,818,120, which represents the overcollection in rates of FAS 106 OPEBs expense, compared to the actual expense incurred. This amount reflects the addition of $16,300,260, which represents a regulatory liability in this rate case and the unamortized portion of the regulatory liability of $16,517,860 in Case No. ER-2008-0318. Both of these amounts were calculated based on the estimated balances projected as of January 31, 2010, the end of the true-up period. The Staff has also included a 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 FAS 106 OPEBs tracker.

b. Annualization

The Staff also annualized OPEB expense to reflect the 2009 FAS 106 cost provided by AmerenUE'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 FAS 106 expense included in rates and the amount actually incurred and funded by AmerenUE.

Additionally, Staff has adjusted the test year OPEB expense to account for the VSE and ISP which called for the elimination of certain management positions within AmerenUE and AMS. Staff expert witness John P. Cassidy discusses the VSE and ISP in detail under that section of this Cost of Service Report.

Since some of AmerenUE's management and administrative functions are provided by AMS employees, AmerenUE's OPEB expense includes costs that are allocated from AMS.

Staff Expert/Witness: Kofi Agyenim Boateng

7. Other Employee Benefits

The Company currently offers employees medical, dental, vision and life insurance, long-term disability and 401k benefits. The Staff has reflected in the cost of service the actual 12 months ending September 30, 2009 level of benefits adjusted to remove benefit costs associated with employees that are no longer with the Company due to the VSE and ISP. The Staff will continue to analyze actual benefit cost information as it becomes available through January 31, 2010, 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 compensation, long-term compensation, and an exceptional performance bonus program. Some of AmerenUE's incentive compensation costs are allocated from AMS, as AMS provides various management and administrative functions to AmerenUE.

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

- Executive Incentive Plan - Officers level,
- Executive Incentive Plan - Managers and Directors level
- 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 AmerenUE. 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 AmerenUE's earnings, safety, reliability, and/or customer satisfaction. The Company's EIP-O is entirely funded based on earnings per share (EPS).

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 earnings per share (EPS) and seventy-five percent is based on operational performance as measured by KPIs and individual performance as determined by supervisors through the performance appraisal process.

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.

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.

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.

The Exceptional Performance Bonus Plan (EPBP), unlike the short-term 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 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, EPB 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 AmerenUE'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 AmerenUE rate case, Case No. ER-2008-0318, the Commission decided that, "AmerenUE 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 AmerenUE and AMS. Staff expert 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 AmerenUE'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 earnings per share should be borne by ratepayers, the Staff has removed the incentive compensation that was capitalized from 2002 through the end of March 2009 from the plant in service and reserve balances.

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

In addition to the other compensation available (base and incentive), AmerenUE 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 surveyed other large utilities in Missouri to see what these companies spent to process recent rate cases. The largest amount the Staff found was $1,218,713 for the processing of three interrelated general rate increase cases, those for Kansas City Power & Light Company, the electric operations of KCP&L Greater Missouri Operations Company and the steam operations of KCP&L Greater Missouri Operations Company, Case Nos. ER-2009-0089, ER-2009-0090 and HR-2009-0092, respectively. These three cases required the development of four separate costs of service. Based on this survey, the Staff has determined that $1,000,000 should be sufficient for AmerenUE to process Case No. ER-2010-0036.

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 AmerenUE charged to its utility accounts during the test year. The Staff proposes adjustments to disallow various dues and donations that were included by AmerenUE 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 Healing the Children and The United Way.

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 Expert/Witness: Lisa M. Ferguson

3. Edison Electric Institute (EEI) 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 that 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, 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 adjusted AmerenUE's insurance expense to annualize that expense based on the premiums paid as of March 31, 2009, the end of the test year.

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. 16, 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.

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, AmerenUE has taken steps to reduce this cost and the September 2008-2009 premium has decreased overall. The Company has indicated that these premiums will have a slight increase but nothing substantial in dollar amount. This item will be reexamined during the true-up audit, when the new premium is available for review.

Staff Expert/Witness: Lisa M. Ferguson

5. Vegetation Management And Infrastructure Inspection Programs

a. Annual Expense

The Staff has adjusted the non-payroll test year expense level associated with AmerenUE's vegetation management and infrastructure inspections programs, to reflect the actual cost incurred during the twelve months ending September 30, 2009. The Staff will re-examine the actual cost through the end of the true-up period, January 31, 2010, to determine if further adjustment is necessary and/or appropriate.

b. Trackers

In Case No. ER-2008-0318, the Commission allowed AmerenUE to recover, over a three year period, 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. The Staff has adjusted the test year expense to included one-third of the amount deferred.

Also as part of that rate case, the Commission allowed AmerenUE to defer 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 October 31, 2008 through February 28, 2009. The Staff has adjusted the test year expense to included one-third of the amount deferred.

In addition, the Commission allowed AmerenUE to defer 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 the cost of service in

Case No. ER-2008-0318, $54.1 million and $10.7 million, respectively. On page 14 of his direct testimony prepared on July 24, 2009, and prefiled in this case, Company Witness Ronald C. Zdellar states that AmerenUE was in compliance with the Commission's vegetation management rule beginning in January of 2008. He also states that AmerenUE is in compliance with the Commission's infrastructure inspection rule. From the Staff's point of view, both of these programs have reached a mature status and are manageable by the Company. Therefore, any amounts deferred by AmerenUE in relation to the tracker base established by the Commission in Case No. ER-2008-0318 for the vegetation management and infrastructure inspection programs should not be included in the cost of service for Case No. ER-2010-0036, or any future general rate case.

Staff Expert/Witness: Stephen M. Rackers

6. Customer Deposit Interest Expense

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

Staff Expert/Witness: Lisa M. Ferguson

7. Property Tax Expense

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 developed its property tax rate based on the Company's estimate of the 2009 taxes, which are paid based on investment at January 1, 2009. The reasonableness of this estimate was verified based on an examination of the taxes paid during the test year and the increases in both plant and assessed values.

Staff Expert/Witness: Lisa M. Ferguson

8. Uncollectible Expense

Uncollectible expense is the portion of retail revenues that AmerenUE 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, AmerenUE is subsequently successful in collecting some portion of the delinquent amounts owed. The Staff examined the actual thirteen-year history of billed revenues that were never collected (net write-offs) from March 1997 through March 2009 and has included in the cost of service calculation a three-year average 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 AmerenUE'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 and promotional advertising from recovery in rates. The Staff found no evidence that AmerenUE engaged in any political advertising. Costs for safety advertising and general advertising directed towards the benefit of existing customers were unadjusted by the Staff. In addition, as provided in response to Staff Data Request No. 276, the Company has increased its advertising expense for calendar year 2008 almost 100% from 2006. It is also budgeted that advertising will increase another 28% as compared to 2008 for calendar year 2009 and 3% from 2009 for calendar year 2010. The Company has stated, also in response to Staff Data Request No. 276, that the purpose of the increase in advertising was to improve the flow of information to its customers. Though no specific category of advertising was specified, the Company believes the most efficient and effective way to communicate with its customer base is through the ramping up of advertising.

Staff Expert/Witness: Lisa M. Ferguson

10. Franchise Taxes

The Staff has eliminated the franchise taxes (otherwise known as gross receipt taxes) from AmerenUE's expense; as such taxes are merely a pass-through item to AmerenUE. AmerenUE bills and collects the taxes from its customers, and then passes the taxes on to the municipal taxing authorities. The Staff proposes an adjustment in an identical amount to remove franchise taxes from AmerenUE's test year revenues, so that these taxes have no effect on the Company's revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

11. Test Year Storm Cost

The Staff proposes to normalize test year non-labor related storm costs based on a four-year average of historic non-labor related storm costs for all storms that occurred between July 1, 2005 and June 30, 2009. The Staff excluded all costs related to storms that occurred between July 1, 2006, and December 31, 2006, from its four-year average. On page 77 of its

Report and Order in Case No. ER-2007-0002 the Commission stated: "The Commission concludes that AmerenUE's 2006 storm related operating and maintenance shall be offset against its 2006 SO_2 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 also excluded all costs related to the January 13, 2007, ice storm from its four-year average. The Staff excluded these costs because they are already addressed by the inclusion of an amortization for these costs, as approved by the Commission in Case Nos. EU-2008-0141 and ER-2008-0318.

The Staff's test year non-labor related storm cost normalization adjustment removes $3,977,675 of non-labor related storm costs from the cost of service calculation. The Staff proposes that the Company be allowed to recover this approximately $4.0 million of extraordinary storm costs over five years beginning with the effective date of general rates established in this rate case. The Staff has included $795,535 in its cost of service calculation for this proposed amortization. The Staff will describe in detail all storm cost amortizations proposed for inclusion in rates in the next section of this Cost of Service Report.

Staff Expert/Witness: Stephen M. Rackers

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, AmerenUE's cost of service was reduced by $4,442,000 in storm costs and the Company was allowed to recover an amortization of $800,000 annually from July 1, 2007, through June 30, 2012. During the test year ending March 31, 2009, the Company recorded a full twelve months of the annual amortization or $800,000. Therefore, no adjustment is necessary to annualize the storm amortization that was established as part of Case No. ER-2007-0002.

b. Storm Cost from ER-2008-0318

As part of an agreement reached in Case No. ER-2008-0318, AmerenUE's cost of service was reduced by $4,856,527 for extraordinary storm costs that had occurred during the test year and the Company was allowed to recover an amortization of $971,400 annually from March 1, 2009 through February 28, 2014. With regard to this rate proceeding, the Company recorded one month or $80,950 of the $971,400 annual amortization, during the test year ending March 31, 2009. The Staff included an $890,450 adjustment in the cost of service calculation to annualize this storm amortization to a $971,400 annual level.

c. Storm Cost from Case No. ER-2010-0036

As previously discussed, the Staff removed $3,977,675 of storm costs from the cost of service calculation. The Staff instead proposes to amortize this adjusted storm cost level that exceeds the normalized level over a period of five years. The Staff proposes to begin this amortization upon the effective date of rates as established by this Commission in this rate proceeding. The Staff has included $795,535 in the cost of service calculation for this proposed storm amortization adjustment.

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 AmerenUE 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, 2009, the Company recorded one month or $409,353 of the annual $4,912,236 amortization. The Staff has included a $4.5 million adjustment in the cost of service calculation in order to annualize this storm amortization.

Staff Expert/Witness: Stephen M. Rackers

<u>13. Lease Expense</u>

During the test year, AmerenUE incurred lease expense on various buildings and equipment it uses in the provision of service. The Staff reviewed AmerenUE's test year lease expense for the test year ended March 31, 2009. There is a slight decrease in the overall expense level.

Staff Expert/Witness: Lisa M. Ferguson

14. Callaway Refueling Adjustment

AmerenUE's Callaway nuclear power plant undergoes a refueling and maintenance outage process approximately every 18 months. While refueling takes place, the Company typically completes numerous maintenance activities, performs inspections and testing and also completes any necessary capital improvements. The Company refueled the Callaway nuclear power plant during October and November 2008 which was within the test year ending March 31, 2009. 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. The normalization adjustment removes one third of approximately $23 million of the test year level of non-labor maintenance project costs. All labor related costs associated with the Callaway refueling are addressed in the Staff's payroll annualization as discussed by Staff witness Roberta A. Grissum. The Staff adjusted expense to eliminate approximately $7.7 million from the Staff's cost of service calculation in order to normalize non-labor related maintenance expenses associated with the Company's refueling of the Callaway nuclear power plant.

Staff Expert/Witness: Roberta A. Grissum

15. Training Cost

In Case No. ER-2008-0318 the Commission added $1,410,000 to AmerenUE's cost of service to fund increased training staff. The Commission also added $360,000 to AmerenUE'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. The Staff has included an annualized level of the amount spent through September 30, 2009. The Staff will re-examine this item during the true-up audit and determine whether any further adjustment to the cost of service is necessary.

Staff Expert/Witness: Stephen M. Rackers

16. Security Cost

AmerenUE has experienced ** ____ ______________ **. The Staff has made an adjustment to the test year to recognize this change in AmerenUE's security cost and cost of service.

Staff Expert/Witness: Stephen M. Rackers

17. Coal Power Plant Maintenance Expense

The Staff is recommending a normalization of the non-labor maintenance expense for AmerenUE's coal power plants. Since the coal power plant maintenance expense experienced during the test year ending March 31, 2009, was significantly higher than the levels experienced in previous years, the Staff does not believe the test year expense is reflective of the expected ongoing expense level. Therefore, the Staff normalized the non-labor coal power plant maintenance by adjusting the test year expense to reflect the three-year average for the period beginning April 1, 2006 through the end of the March 31, 2009 test year.

Staff Expert/Witness: Roberta A. Grissum

18. Low Income Weatherization

The Staff included an adjustment to increase test year expense to reflect the funding allowed in the previous rate case No. ER-2008-0318.

Staff Expert/Witness: Stephen M. Rackers

G. Income Tax

Income tax expense has been calculated consistent with the methodology used in AmerenUE's most recent Missouri rate cases, Case Nos. ER-2007-0002 and ER-2008-0318.

Staff Expert/Witness: Stephen M. Rackers

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IX. Depreciation

A. Summary

The Staff conducted a depreciation study of the capital assets of AmerenUE, (Missouri Operations), including an analysis of the accumulated reserve for depreciation. In preparation for this study, Staff conducted on site tours of AmerenUE plant.

Staff reviewed the company's depreciation study, which was included with the direct testimony of John Wiedmayer and Larry Loos prefiled in this case. Staff also reviewed the depreciation studies and the depreciation-related issues associated with AmerenUE's two most recent prior general electric rate cases, Case Nos. ER-2007-0002 and ER-2008-0318.

Staff's recommended overall plant depreciation rate in this case is higher than the overall plant depreciation rate the Commission ordered in AmerenUE's last rate case. For the depreciable plant balances at the end of 2008, the depreciation expense increases from approximately $325.1 million to $328.1 million, an increase of $3.0 million, or 0.9%.

The depreciation rates AmerenUE proposes would increase the currently ordered annual depreciation expense from approximately $325.1 million to $343.9 million, an increase of approximately $18.8 million, or 5.8%.

AmerenUE and the Staff did not use the same study methods to determine average service lives and net salvage for AmerenUE's Steam Plant and Hydraulic Plant production equipment. AmerenUE and the Staff did use the same study methods for AmerenUE's Nuclear Plant, Other Production Plant, Transmission Plant, Distribution Plant and General Plant. Schedule AWR-1, within Appendix 4, appended to this report is a condensed summary comparison of depreciation rates and annual accruals comparing continuation of current rates versus AmerenUE and Staff proposed rates. Schedule AWR-2, within Appendix 4, appended to this report are comparisons, by plant account, of Commission-ordered depreciation rates in Case Nos. EC-2002-1, ER-2007-0002, and ER-2008-0318, as well as the AmerenUE's and the Staff's proposals in their direct in this case.

AmerenUE performed its depreciation study in accordance with the Commission's *Report and Order* in Case No. ER-2008-0318, in which the Commission directed:

> When it prepares its next depreciation study, AmerenUE shall provide for each account (1) the book reserve amount, (2) the theoretical reserve

> amount, (3) the remaining life years, and (4) the whole life depreciation rate with the reserve variance amortized over the average remaining life.

AmerenUE's whole life depreciation rates and accruals include lifespan treatment of steam plant and hydraulic plant, and are shown in Appendix 4, Schedule AWR-3 under the heading labeled "Annual Accrual Compare (no amortization)." AmerenUE chose to amortize reserve variances over the remaining life of a given generating plant facility by combining the whole life depreciation accrual and the amortization accrual together, resulting in remaining life depreciation rates. In AmerenUE's proposal, the remaining life for each steam plant, the nuclear plant and each hydraulic plant are fixed calendar dates. The resultant depreciation rates and accruals are shown in Appendix 4, Schedule AWR-3 under the heading "Company Proposed Remaining Life Amortization Adjustment".

AmerenUE chose to use the lifespan method to study depreciation for the Steam Plant, Nuclear Plant and Hydraulic Plant accounts. The result is a different set of depreciation rates proposed for each steam plant facility and each hydraulic plant facility. Thus, the AmerenUE proposed rates shown in the tables in Appendix 4, Schedules AWR-2 and AWR-3 appended to this report for total steam plant or total hydraulic plant include remaining life amortization, life span treatment, and a weighted average of different depreciation rates proposed for each facility. This makes comparison of Staff and Company proposed depreciation rates for steam and hydraulic plant difficult.

Staff used the lifespan method to study depreciation rates for the Nuclear Plant accounts only. For the Nuclear plant accounts, Staff used a fixed annual amortization of a negative $7,199,461 to correct for the over-accrued reserve, (Schedule AWR-3, within Appendix 4). This amortization was calculated to reduce the reserve imbalance to zero at the end of the nuclear plant life (60 year license). The reserve imbalance is a result of extending the plant life for depreciation purposes - based on its license length - from 40 to 60 years. The Staff's depreciation study results, when combined with the $7,199,461 negative amortization, result in expense similar to AmerenUE's proposed overall annual accrual for all Nuclear Plant Production equipment.

In its depreciation study Staff treated all plant, other than the Nuclear Plant, as mass property. The study revealed a large over-accrual in account 344, Combustion Turbine Generators. This over-accrual appears to result from the depreciation rates set for this equipment in the past exceeding actual retirement history for years prior to AmerenUE's 2006 general electric rate increase case, Case No. ER-2007-0002. Staff applied a $5,000,000 amortization (Schedule AWR-3, within Appendix 4) to reduce the annual accrual for this account.

B. Definition Of Depreciation

Depreciation is the loss, not restored by current maintenance, which is due to all factors causing ultimate retirement of the property. These factors include wear and tear, decay, inadequacy, obsolescence, changes in the art, and requirements of public authorities.

The purpose of depreciation in a regulatory setting is to recover the cost of capital assets over the useful lives of the assets. The depreciation rate for each plant account is designed to recover, over the average service life of the assets in that account, the original cost of the assets plus an estimate for any cost of removal less scrap value. Annual depreciation expense for a plant account is the depreciation rate for that plant account multiplied by the balance of plant in that account. The annual depreciation expense returns to the company's shareholders a portion of the costs of the capital assets. In a regulatory setting this return is commonly referred to as a return of equity. The remaining portion of the costs of the capital assets of the company (net plant-in-service) is returned to the company's shareholders in the future. The company is permitted during this period to earn a return on the capital assets in rate base, commonly referred to as a return on net plant-in-service, a component of rate base. In a regulatory setting this return is commonly referred to as a return on equity.

C. Depreciation Study

Staff conducted on site tours of the following facilities:

- Meramec coal-fired plant and associated station equipment,
- Labadie coal-fired plant and associated station equipment,
- Venice retired steam plant, and combustion turbine generators,
- Callaway, nuclear plant general facilities tour,
- Osage, hydraulic turbines, station equipment and dam,
- Taum Sauk, pump storage plant, penstock, and upper reservoir,

- Moreau distribution substation and combustion turbine generator equipment,
- Project Power On activities in the Jefferson City area.

Staff's depreciation study results are shown in Appendix 4, Schedule AWR-3 appended to this report which is a comparison, by account, as of Dec. 31, 2008, of plant original cost (with adjustments by Staff), accumulated reserve variances, proposed reserve variance amortization, and depreciation accruals. Where Company proposed mortality rates and Staff proposed mortality rates are not the same, the theoretical reserve computation is affected, and the resultant reserve variances between the proposals differ. Schedule AWR-4, within Appendix 4, is a comparison, by account, of book reserves, theoretical reserves, and Staff adjustments made to AmerenUE's booked plant and reserve balances the Staff made for purposes of conducting its depreciation study. Staff used the straight line method, broad group-average life procedure and whole life technique depreciation system for its depreciation study of AmerenUE's capital assets. This is simply straight line depreciation of a group of assets assigned to an account. The whole life technique does not include an adjustment factor to address over- or under-accruals in the accumulated reserve for depreciation. Staff uses the following formula to calculate a depreciation rate for each plant account:

Depreciation Rate = (100 % -Net Salvage %) ÷ (Average Service Life).

This is consistent with the Commission's Depreciation Rate Formula from its Report and Order in The Empire District Electric Company Case No. ER-2004-0570. As shown in the formula, average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. The Staff calculated depreciation rates for each plant account based on the average service life and net salvage percentage determined applicable to each account as shown in Appendix 4, Schedule AWR-2. That determination requires engineering experience and informed judgment and is addressed in detail below.

D. Average Service Life

For each plant account, the average service life (ASL) is the expected period, in years, of the useful service of each unit of property in that account, (e.g. electric poles), regardless of when that unit was first put into service—its placement date. An account's ASL is developed in four steps. The first step is to review historical mortality data and historical salvage/cost of removal data. The data are checked for reasonableness and to ensure sufficient data exist to perform a statistically significant analysis. In addition, Staff reviews the data to determine if retirements recorded in one historical database are also recorded in the other historical database. The second step is to gain familiarity with the facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with operations' personnel, engineers, accountants, and other depreciation experts. Current developments such as technological changes, environmental regulations, regulatory requirements, or accounting changes can all affect the average service life of property in an account. Different vintages of plant being manufactured from different materials, changes in installation practices, or the development of a life extending maintenance procedure are some examples of factors contributing to changes in average service lives. Difficulty in constructing new generation plant has led utilities to choose to spend the incremental costs of increasing the capacity of existing plants or extending the life of existing plants; i.e., expenditures at the Callaway Production Plant has increased the efficiency, plant output, and is expected to extend the life of its original generating units.

The third step is to perform a statistical analysis of the retirement experience of each utility plant account, followed with analysis of the results for reasonableness for the type of plant in question. To evaluate the retirement experience of AmerenUE's plant accounts, depreciation software used by Staff analyzes historical plant data by calculating the ratio of retirements to exposures by age, then solving for the percent surviving by age to develop a survivor curve for an account. The required data are plant additions in dollars by year, or vintage, and retirements from each vintage in dollars by year. The exposures at a given age are the dollars remaining from the various vintages that have lived to that age. The retirement ratio is the dollars retired during an age interval divided by the exposures at the beginning of that interval. The survivor ratio is then calculated by subtracting the retirement ratio from "1". Multiplying each successive survivor ratio by the percent surviving of the previous age will generate a survivor curve. This original survivor curve can then be smoothed and fitted to an empirically developed statistical model known as the Iowa curves. The Iowa curves are widely accepted models of the life characteristics of utility property. The system of Iowa curves is a family of 176 types of utility and industrial property. The curves were developed at the Iowa Engineering Experiment Station at what is presently known as Iowa State University. The Iowa curves were first published in 1935 and reconfirmed in 1980. Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. The original survivor curve is mathematically and visually matched with various Iowa curves to determine which has the most appropriate fit, either for a significant portion of the curve or just a specified portion of the curve. The average service life of an account's original survivor curve is estimated as the area under the selected Iowa curve. The fourth step is using engineering experience and informed judgment to the aggregate of the first three steps in the process to assign an appropriate ASL for each plant account.

Staff's life estimates for AmerenUE Nuclear production plant accounts are truncated at the end of the expected license renewal date for the Callaway plant, Nov. 2044.

Staff recommends that the Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal.

As noted earlier the average service life is just one of two factors determining a given depreciation rate. The second factor, net salvage percentage, is discussed next.

E. Net Salvage Percentage

The second factor in determining a given depreciation rate is the net salvage percentage. Consideration is given to the future net salvage (or cost or removal) that property in an account may experience.

Net Salvage = Gross Salvage -Cost of Removal

Gross salvage is the recovered marketable value of retired plant. Cost of Removal is the cost associated with the retirement and disposition of plant from service. Negative net salvage occurs when the cost of removal exceeds gross salvage. A negative net salvage is commonly referred to as an expense or net cost of removal and a negative net salvage percentage is called a net cost of removal percentage. Today, most accounts experience a net cost of removal; therefore the net salvage percentage in the depreciation calculation is negative which results in an increase to overall depreciation expense.

Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage realized by AmerenUE. This is consistent with the Commission's policy for net salvage from its *Report and Order* in The Empire District Electric Company's 2004 general electric rate increase case, Case No. ER-2004-0570. Staff performed an annual overall salvage analysis, a rolling 3-year band analysis, and a last five year average analysis for deriving net cost of removal percentages. This review showed that in some accounts there was no recent history of costs and that, in other accounts, timing of retirements and costs produce unreliable estimates of net-cost-of removal percentages. Staff used engineering judgment to select the result which best represented the activity observed in the overall account. An example is Transmission plant account 355 (Poles and Fixtures) where recent years show a large positive net salvage, which is not typical of the account history, so Staff chose the (lower) overall account history average of negative 30%.

Depreciation software uses the selection of a specific Iowa curve and net salvage percentage for each plant account to calculate the account's theoretical accumulated reserve for depreciation, discussed next.

F. Analysis of Accumulated Reserve for Depreciation

Another analysis performed with a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. This analysis illustrates whether prior depreciation estimates have differed significantly from actual experience. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date (December 31, 2008) to a theoretical accumulated reserve for depreciation, given the revised depreciation parameters selected for each account, as shown in Appendix 4, Schedules AWR-2. Staff used the December 31, 2008 reserve balances shown in AmerenUE's 2008 depreciation study, with one notable exception. This exception is for accounts where a Square Curve (SQ) is used as the depreciation model. These adjustments are listed in the far right column of Schedule AWR-4, and are also the same adjustments used to correct Plant Balances as of Dec. 31, 2008 shown in Schedules AWR -1 and AWR-3, within Appendix 4.

The square curve depreciation model is used for accounts containing many small items spread over many areas of the company, or accounts containing hard to track items. These accounts are:

Acc. No.	Life	Description
336	50 SQ	Hydraulic Plant, - Roads, Railroads and Bridges
359	50 SQ	Transmission Plant, - Roads and Trails
391	15 SQ	General Plant, - Office Furniture and Equipment
391.2	5 SQ	General Plant, - Personal Computers
393	20 SQ	General Plant, - Stores Equipment
394	20 SQ	General Plant, - Tools, Shop and Garage Equipment
395	20 SQ	General Plant, - Laboratory Equipment
397	15 SQ	General Plant, - Communications Equipment
398	20 SQ	General Plant, - Miscellaneous Equipment

This treatment is appropriate for accounts consisting of items that tend to get lost, broken, replaced, or otherwise cease to be used and useful, without the accounting function being notified. No "retirement work order" gets written to remove small, forgotten, or misplaced items from the books, and the property tends to remain on the books "forever." For depreciation purposes a life model is chosen, such as 50 or 20 years, and all plant that exceeds that age, (age 51 or 21 years) is retired. Interim retirements (prior to 50 or 20 years) are not considered. In each of the above accounts, AmerenUE's books show equipment still on the books that has exceeded the chosen life model. Staff has adjusted plant and reserve balances in these accounts to remove (retire) plant still shown to be in service beyond the chosen life. The depreciation expense (i.e. 5% for 20 year life) is applied only to plant which has not exceeded the chosen life. The theoretical depreciation reserve is computed only against plant which has not exceeded the chosen life.

The amount in a depreciation reserve account is the amount for plant investment and net cost of removal that has been recovered in depreciation rates over the life of the capital assets, reduced by retirement amounts, costs of removal experienced, and transfers out, and increased by actual salvage proceeds collected, and transfers in. The aggregate of the depreciation reserve accounts is known as the "accumulated reserve for depreciation." The theoretical accumulated reserve for depreciation amount can be viewed as the level of accumulated depreciation reserve that would exist today if the selected depreciation parameters had been used since the inception of the plant being placed in service. If the amount of the actual accumulated reserve for depreciation is more than the theoretical amount, there is an over-accrual. Conversely, if the actual accumulated reserve for depreciation is less than the theoretical amount, there is an under-accrual.

The need for, the magnitude of, and the timing of an adjustment should be based upon consideration of several factors: the characteristics of the account, the causes of the difference, and the year-to-year volatility of the accumulated provision for depreciation, as well as the magnitude of the imbalance. Future service life cannot be estimated to a degree of certainty that guarantees that the actual life will match the estimated service life. In fact, the depreciation estimation process is dynamic, and it is possible, and likely, that the currently determined ASL that Staff is recommending will differ from the ASL that occurs. Staff is not proposing any transfers of reserves between accounts to correct for over- or under-accruals at this time.

To correct for reserve imbalances, a fixed or remaining life amortization may be used. The Staff proposed depreciation rates result in a book accumulated reserve in excess of the theoretical reserve of $698,819,221 for all plant and equipment. The majority of this reserve imbalance, 70%, is in the Nuclear Plant Accounts and the Combustion Turbine Generator account. Staff proposes a fixed annual amortization for the Nuclear plant accounts of a negative $7,199,461. Staff proposes a fixed annual amortization of a negative $5,000,000 for account 344, Combustion Turbine Generators. The remaining 30% of the imbalance is in the Steam Plant Accounts. Staff does not propose an amortization in the Steam Plant Accounts. Staff recommends the excess reserve in the Steam Plant Accounts be left as is until the effects of potential environmental regulations concerning the operation and life of these coal burning facilities may be evaluated.

G. Lifespan versus Mass Property Treatment for Depreciation Studies

The Company has proposed retirement treatment for steam and hydraulic production plants which Staff does not support. AmerenUE has proposed the treatment of individual steam and hydraulic plants as lifespan property. Staff has proposed treatment of all steam production plant and all hydraulic plant as mass property.

Under Lifespan treatment, each individual production site is treated separately. A future retirement date is set, and retirements occurring prior to that date are treated as interim retirements. The average service life is the projected life adjusted downward to reflect interim retirements. Final retirements are retirements that occur when the plant is shut down. Inclusion of final retirements is inherent in the lifespan computation. Under this treatment all equipment, including equipment installed in recent years, will be retired at the shutdown date. Thus each plant site ends up with its own specific set of depreciation rates. Appendix 4, Schedule AWR-2 shows widely different Iowa Curve designators by AmerenUE versus the Staff. Under Life Span treatment, the Iowa Curve designation, (year and type, i.e. 75 R2), is simply a description of the interim survivor curve which is truncated at the projected retirement date.[17] Further, the net salvage numbers included in the depreciation calculation are also "truncated," since there will be no further net salvage past the retirement date. Staff assumes AmerenUE will request additional funds from rate payers for the cost of removing these facilities when they are shut down.

Under Mass Property treatment, all steam plant property is lumped together without regard to its physical location, and all hydraulic plant property is lumped together without regard to its physical location. Retirement of a plant site is treated as part of the mass property in that there is no distinction between interim and final retirements. Retirements that occur when an individual plant unit is actually retired are included in the mortality study and derived survivor curves. The depreciation for any one site retirement is averaged over all plant equipment. Each steam plant and each hydraulic plant is assigned an identical set of depreciation rates. When a plant unit is retired, future mass property depreciation studies will use the interim and final retirement data from the retired unit as well as the interim retirements from the operating units. This treatment incorporates historical retirement data into the depreciation rates to compensate for future individual plant unit retirements. Retirement of individual units, including recently installed equipment, is assumed in the overall rate without selection of specific retirement dates for depreciation purposes. These situations are included in the mass property mortality study when final retirements and cost of removal are included in the data. Under true mass property treatment, the company’s need for compensation for the shutdown and/or removal of an individual steam plant or hydraulic plant is considered throughout the life of the plant.

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[17] In this example, the 75 in the curve designator by itself is not usable to determine a depreciation rate. The 75 is not the average service life.

For the mass property treatment, the Iowa Curve designator (i.e. 48 R1.5) is the full definition of the mortality characteristics observed in the account.[18] Also, the net salvage numbers used in the depreciation calculation are not truncated.

The two curve designators used in the examples above are representative of the difference seen from the two treatments. A lifespan (interim curve) of 75 R1.5 may become a mass property (whole life curve) of 48 R3.

Staff believes the AmerenUE steam production plants, which are located at multiple sites (4) with multiple steam production units at each site (12 total), should be treated as mass property. Significantly, if the data base studied for treatment as Mass Property contains representative retirement data for plants that have been retired, and the dates chosen for Lifespan treatment are dates derived from the same retirement history, then the overall plant depreciation rates for both methods should be very close to the same number.

Staff recommends treatment of steam plant as Mass Property because it removes the reliance on uncertain predictions of future retirement dates for specific sites, or steam units, that is implicit in the Lifespan treatment. In addition to being unreliable for any specific steam unit, a fixed retirement date for a specific plant site can result in a fixed mentality towards the actual treatment of that site, regardless of changing circumstances that might result in beneficial continuation of the use of the site.

Staff recommends treatment of hydraulic plant as mass property. For the Osage, Taum Sauk, and Keokuk facilities Staff disagrees with AmerenUE's use of the expiration date of the current FERC licenses as a certain retirement date.[19] Experience has demonstrated that FERC licenses for hydraulic facilities are renewed with modified operating requirements, and the plant operation continues. Thus, Staff does not agree with the dates AmerenUE used for the lifespan treatment to determine depreciation rates for these facilities.

Staff used a Mass Property type treatment to study hydraulic plant mortality, recognizing that this approach has inherent limitations for these specific facilities. There are only three facilities which yield limited mortality study data. The database does include a major facility retirement, but these numbers may not be used due to the nature of the retirement and insurance

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[18] In this example, the 45 is the average service life, and the curve shape R1.5 is used to determine theoretical accumulated reserve and remaining life.

[19] The Company's retirement date for Keokuk, which operates without a FERC license, is based on the FERC license expiration dates for the other two facilities.

compensation. However, Staff was able to use available relevant data, including additional data on retirements of turbines which were omitted from the data AmerenUE provided December 31, 2008, and engineering judgment to propose reasonable depreciation rates. The overall depreciation rate Staff proposes for AmerenUE's hydraulic plant is 1.92%, versus AmerenUE's proposed 2.55%.

The current ordered rate for hydraulic plant is 1.54%. The main reason for the increase in Staff's proposed rate from the ordered rate of 1.54% to 1.92% is the availability of additional retirement data which Staff did not have in the prior rate case. In recent years long lived original equipment such as dam gates and turbine generators have entered a replacement cycle. An example is Osage, where six of the eight original main turbogenerators have recently been replaced, (4 in just the past three years), and both auxiliary turbogenerators (2 kW cold start units) are currently being replaced).

H. Recommendations

Staff recommends that the Commission order the depreciation rates proposed in Schedule AWR-5 within Appendix 4.

Staff recommends the Commission order an amortization of a negative $7,199,461 for AmerenUE's Nuclear Plant accounts, and a negative $5,000,000 for AmerenUE's Generator account (344). This is a reduction of $12,200,000 in annual depreciation expense.

Staff recommends the Commission order AmerenUE review the retirement of property in plant accounts using the square curve depreciation model. This review is to insure depreciation expense is booked only on property that has not exceeded the average service life, and that for depreciation purposes no property is retired prior to its average service life.

Staff Expert/Witness: Arthur W. Rice

X. Fuel Adjustment Clause (FAC)

A. Recommendations

The Staff recommends that the Commission approve, with modifications, the continuation of AmerenUE's Fuel Adjustment Clause ("FAC"). Staff has reviewed the minimum filing requirements documents AmerenUE provided in Schedule LMB-E1-1 attached to the prefiled direct testimony of AmerenUE witness Lynn M. Barnes and believes that with these documents AmerenUE has complied with the minimum filing requirements contained in 4 CSR 240-3.161(3) to inform the public of AmerenUE's requested changes to its FAC in this case. To reduce customer confusion the Staff recommends that the Commission order AmerenUE to stop using the acronym FAC on its customers' bills and, instead, use the words "Fuel and Purchased Power Adjustment."

Staff agrees that the Net Base Fuel Cost of AmerenUE's FAC should be re-based in this case. Staff at this time does not have an estimate for the Net Base Fuel Cost, but will include its estimate of the appropriate Net Base Fuel Cost when it files its Class Cost-of-Service and Rate Design testimony on January 6, 2009.

Staff also agrees with AmerenUE's refinements to its FAC in the true-up process, inclusion of the cost of quality adjustments related to the sulfur content of coal assessed by coal suppliers, and to AmerenUE's proposed changes in the Taum Sauk factor and loss factors. These will all be discussed further in this section of the report.

Staff also recommends: 1) additional language to AmerenUE's FAC concerning the form of electronic workpapers to support AmerenUE's Fuel and Purchased Power Adjustment filings and 2) that the Commission order AmerenUE to provide or make available information and documents to assist Staff during its performance of FAC tariff, prudence and true-up reviews.

1. Summary of AmerenUE's current FAC

In AmerenUE's last rate case, Case No. ER-2008-0318, the Commission approved the *Stipulation and Agreement As To All FAC Rate Design Issues* permitting AmerenUE, for the first time, to use a FAC. The primary features of AmerenUE's present FAC (original sheet numbers 98.1 – 98.7, with an effective date of March 1, 2009) include:

- Three 4-month accumulation periods: February through May, June through September and October through January;
- Three 12-month recovery periods : October through September, February through January and June through May;
- Fuel and Purchased Power Adjustment rate filings to be made not later than August 1, December 1 and April 1;
- A 95%/5% sharing mechanism;

- Fuel and Purchased Power Adjustment rates for individual service classifications are adjusted for the three AmerenUE service voltage levels, rounded to the nearest 0.001 cents, and charged on each applicable kWh billed; and
- True-up year of March 1 through the last day of February of the following year March 1.

The Fuel and Purchased Power Adjustment formula includes the following factors of interest specific to AmerenUE:

- Taum Sauk factor, which is used to reduce actual fuel costs in accumulation periods to reflect the value of Taum Sauk that is a credit in Fuel and Purchased Power Adjustment rate filings until the next rate case or until Taum Sauk is placed back into service.
- Blackbox Settlement Amount of $3 million for annual reduction to actual fuel costs, with $1 million in each four-month accumulation period. This Blackbox Settlement expires on September 1, 2010.

At this time AmerenUE has made two Fuel and Purchased Power Adjustment rate filings. The first Fuel and Purchased Power Adjustment rate filing (Case No. ER-2010-0044) was made on July 31, 2009, for a "partial" accumulation period of March 1 to May 31, 2009.[20] Actual fuel and purchased power expenses less off-system sales were $13,271,127 under the base fuel and purchased power expenses less off-system sales amount for the accumulation period. The Fuel and Purchased Power Adjustment rate was set to refund to customers 95% ($12,607,571) during the first recovery period. During the Staff's review of this filing, the Staff identified some normal learning curve-type issues related to the calculation of interest and related to the electronic form of filed workpapers. Both of these issues were corrected prior to Commission approval of the Fuel and Purchased Power Adjustment rate for the first recovery period. The second AmerenUE Fuel and Purchased Power Adjustment rate filing was made on November 25, 2009, and Staff is in the process of reviewing this filing.

[20] Accumulation periods were set to keep the number of changes to customers' rates so that two of the recovery periods coincide with change from summer and winter rates. Therefore, the first accumulation period was only for March 2009 through May 2009 instead of four months.

2. Continuation of FAC

The Staff agrees with AmerenUE that the Commission should approve a continuation of AmerenUE's FAC, with modifications. Only eight months have passed since the effective start date of AmerenUE's FAC. AmerenUE staff members have worked closely with the Commission Staff to refine AmerenUE's process for preparing for and making all filings related to the FAC. Staff agrees with AmerenUE's assertion in the prefiled direct testimony of its witness Ms. Barnes that, with regard to AmerenUE's FAC, current conditions have not materially changed from those in the last rate case.

3. Change to True-up of FAC

Ms. Barnes' testimony includes the following language concerning a refinement AmerenUE proposes in the FAC true-up process to allow each true-up to occur after the completion of a full recovery period:

> The purpose of the true-up is to compare the amount calculated for each accumulation period to the amounts actually collected from customers during the recovery period. The amounts collected will vary from the actual net fuel cost change occurring in a given accumulation period because the estimated customer usage during the subject recovery period will always vary to some extent from the actual customer usage experienced during that recovery period. It would seem logical, then, that the true-up period should follow the completion of each recovery period (which in this case would occur after September 2010 for the first accumulation period) rather than following the one-year anniversary of the initial implementation date of the FAC, which falls in the middle of a recovery period. The result of this change could actually increase the number of true-up filings occurring in a twelve-month calendar year based on the completion dates of each recovery period, but it would greatly simplify the process of auditing those filings.

The Staff agrees with AmerenUE's rationale for this change and the changes included in Schedule LMB-E3-5 attached to Ms. Barnes' prefiled direct testimony concerning true-up of AmerenUE's FAC.

4. Adjustments Related to the Sulfur Content of Coal

As part of its *Report and Order* issued in Case No. ER-2007-0002, the Commission established an accounting mechanism to track AmerenUE's SO_2 emission allowances and the premiums that AmerenUE pays for low-sulfur coal. In the current case, and on an ongoing basis, Staff witness Roberta A. Grissum recommends that the current SO_2 tracking mechanism be discontinued and, instead, the premiums AmerenUE pays for low-sulfur coal be accounted for through AmerenUE's FAC. The Staff agrees with Ms. Barnes concerning the inclusion of the "quality adjustments related to the sulfur content of coal assessed by coal suppliers," language addition to the definition of cost of fuel in AmerenUE's FAC tariff.

5. Taum Sauk Factor

The AmerenUE FAC Taum Sauk factor treats AmerenUE's net fuel costs as if the Taum Sauk Plant is operating. The factor is used to reduce actual fuel costs, and remains a component of AmerenUE's FAC until Taum Sauk is placed back into service (now expected in the spring of 2010). AmerenUE has increased the annual value of the operation of Taum Sauk from \$22.7 million in the last case (ER-2008-0318) to \$26.8 million in the current case. After reviewing the testimony of AmerenUE witnesses Lynn M. Barnes and Jaime Haro prefiled in this case, and after discussions within Staff, including Staff engineers, the Staff concludes that, for determining the Taum Sauk factor in AmerenUE's FAC, \$26.8 million is a reasonable annual value for the Taum Sauk operations.

6. Voltage Level Adjustments

AmerenUE provided a system loss study as part of the workpapers of AmerenUE witness William M. Warwick provided to Staff in this case. The Fuel and Purchased Power Adjustment rate is multiplied by voltage level adjustment factors to adjust the Fuel and Purchased Power Adjustment rate for service at secondary, primary and transmission voltages. These voltage level adjustment factors have been updated based on AmerenUE's current loss study as provided in AmerenUE's witness William M. Warwick's workpapers. Staff agrees with the results of the loss study and the adjustment factors in Schedule LMB-E3-5 attached to the direct testimony of AmerenUE witness Lynn M. Barnes prefiled in this case.

7. Additional Tariff Language

In addition to the changes AmerenUE proposes, the Staff proposes the following changes to AmerenUE's FAC: The last sentence in the APPLICABILITY section of Sheet No. 98.1 should be: "All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact."

8. Additional Filing Requirements

To aid the Staff in performing FAC tariff, prudence and true-up reviews, the Commission should order AmerenUE to do the following:

- As part of the information AmerenUE submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include AmerenUE'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 AmerenUE's Midwest Independent Transmission System Operator ("MISO") Ancillary Services Market ("AMS") market settlements and revenue neutrality uplift charges;
- Maintain at AmerenUE'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 AmerenUE has that is in effect;
- Within 30 days of the effective date of each and every nuclear fuel, coal and transportation contract AmerenUE enters into, provide both notice to the Staff of the contract and, at AmerenUE's corporate headquarters or at some other mutually agreed upon place, the contracts for review;
- Maintain at AmerenUE'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 AmerenUE has that is in effect;
- Within 30 days of the effective date of each and every natural gas contract AmerenUE enters into, provide both notice to the Staff of the contract and at AmerenUE'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 AmerenUE hedging policy that is in effect for Staff to retain;
- Within 30 days of any change in an AmerenUE hedging policy, provide a copy of the changed hedging policy for Staff to retain;
- Provide a copy of AmerenUE's internal policy for participating in the MISO ASM, including any AmerenUE sales/purchases from that market for Staff to retain;

- If AmerenUE 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;
- The monthly as-burned fuel report supplied by AmerenUE 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 AmerenUE on the electronic format of this report); and,
- In addition to supplying the information required by 4 CSR 240-3.190(3) for any accidents occurring at a power plant involving serious physical injury or death or property damage in excess of $200,000, provide to the Staff the information for every incident at a power plant in which AmerenUE has any ownership interest that involves serious physical injury or death or property damage in excess of $200,000 in the aggregate.

Staff Expert/Witness: John A. Rogers
Staff Expert/Witness: David C. Roos

B. Tariff Adjustments For Updated Losses

System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) of AmerenUE's system between AmerenUE's generating sources and the customers' meters. In this case, Case No. ER-2010-0036, AmerenUE provided a system loss study as part of the workpapers of AmerenUE's Witness William M. Warwick. The Staff used the information contained in AmerenUE's loss study to develop the following loss multipliers for adjusting the Rider FAC, Rider C and SPS in AmerenUE's tariff in a manner consistent with the loss study.

RIDER C: Adjustments of meter readings for metering at a voltage not provided in rate schedule.

For customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage:

1. Metered at Primary Voltage or higher, meter readings (kWhs and KW) will be multiplied by 0.9512.

For customers on rate schedule 4(M) or 11(M):

2. Metered at 34kV or higher, meter readings (kWhs and kW) will be multiplied by 0.9512.

3. Metered at secondary voltage, meter readings (kWhs and kW) will be multiplied by 1.0513.

4. Delivery at 34kV or higher, served through a single secondary voltage, no Rider C adjustment will apply.

RIDER FAC: Fuel and Purchased Power Adjustment Clause.

The following voltage level adjustment factors should be used:

Secondary Voltage Service	1.0789
Primary Voltage Service	1.0459
Large Transmission Voltage Service	1.0124

Tariff 4(M): Small Primary Service Rate.

The Small Primary Service (SPS) and the Large General Service (LGS) rate classes were combined for the Staff's Class Cost-of-Service for the following reasons. First, both rate schedules serve non-residential customers with billing demands of at least 100 kW. Within this group, a customer may choose to take service at secondary voltage level under the LGS rate schedule or at primary voltage level under the SPS rate schedule. The rate structures are identical, except that the rate levels on the SPS rate schedule have been adjusted for the loss differential between primary and secondary voltages, and to account for customer provisioned transformation equipment.

To maintain consistency with the current loss study, SPS energy rates will be calculated by multiplying the LGS energy rate by 0.9512. The SPS demand rates include the provision for customer-owned transformation equipment and the loss differential between voltages; therefore, the loss differential portion of the SPS demand rate will be calculated by multiplying the LGS demand rate by 0.9512.

Staff Expert/Witness: David C. Roos

C. Fuel Adjustment Clause Heat Rate and Efficiency Testing

4 CSR 240-3.161(2)(P) requires that an electric utility filing to establish a rate adjustment mechanism (RAM) shall file "[a] proposed schedule and testing plan with written procedures for heat rate tests and/or efficiency tests for all of the electric utility's nuclear and non-nuclear generators, steam, gas, and oil turbines and heat recovery steam generators (HRSG) to determine the base level of efficiency for each of the units." In Case Number ER-2008-0318 AmerenUE included such a proposed testing schedule. That proposed schedule was included in testimony of AmerenUE witness Mark C. Birk (Direct Testimony, Schedule MCB-E3). Summarily, with that schedule AmerenUE proposed a heat rate testing interval of twelve (12) months for all generating units, with all steam generating units being tested in December and combustion turbine generating units being tested in August of each year. The Staff's position on heat rate testing intervals is that heat rate/efficiency tests must be conducted within two (2) years of the last tests, with the first testing to be completed within two (2) years of the effective date of the Report and Order in the general rate proceeding that authorized the RAM. Since the Commission authorized AmerenUE's FAC in its *Report and Order* made effective February 6, 2009, AmerenUE needs to complete its first round of heat rate testing by February 6, 2011.

4 CSR 240-3.161(3)(Q) required AmerenUE to file in this case, the results of heat rate tests and/or efficiency tests. AmerenUE did so with the prefiled direct testimony of Lynn M. Barnes, and the Staff has reviewed the results of those tests. AmerenUE included test information for all of its steam-electric plants and a portion of its combustion turbine generating units. The testing methodologies utilized were consistent with the testimony of both Staff and Company witnesses in Case Number ER-2008-0318. The test results and associated data appear to be reasonable. AmerenUE did not file test results for all of AmerenUE's combustion turbine generating units with performance monitoring systems (Goose Creek Unit 6, Raccoon Creek Units 1 and 3, Venice Unit 5, and Kinmundy Units 1 and 2), nor did it file test results for its combustion turbine generating units that do not have performance monitoring systems (Howard Bend, Meramec 1 and 2, Viaduct, Kirksville, Mexico, Moberly, Moreau, Fairgrounds, and Venice 1). Staff observed a heat rate test performed on AmerenUE's Moreau generating unit on August 28, 2009.

From a scheduling perspective, the completed heat rate and efficiency tests documented in this general rate proceeding are not consistent with the schedule submitted in Case Number

ER-2008-0318, however insufficient time has elapsed since the Report and Order in that case to result in a failure to meet Staff's expected testing interval. Staff will continue to review heat rate and efficiency test data submitted by the company for additional completed tests.

Staff Expert/Witness: Michael E. Taylor

XI. Environmental Cost Recovery Mechanism

Among other things, section 386.266 RSMo. Supp. 2009, passed and signed into law in 2005 (Senate Bill 179), authorizes the Commission "to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in [an electric utility's] prudently incurred costs, whether capital or expense, to comply with any federal, state, or local environmental law, regulation, or rule," but only after the Commission has authorized an adjustment mechanism to do so in a general rate case and has promulgated rules. AmerenUE is the first utility to seek such an adjustment mechanism, a mechanism which the Commission has denominated in its rules to be an Environmental Cost Recover Mechanism (ECRM). 4 CSR 240-3.162(1)(D) and 4 CSR 240-20.091(1)(B). The Staff used several criteria in evaluating whether to recommend to the Commission that it establish an ECRM for AmerenUE. Given this evaluation, the Staff is recommending that the Commission, with the conditions detailed in later sections of this report, grant AmerenUE an ECRM.

Staff does points out that if the Commission approves an ECRM for AmerenUE in this case, that with the anticipated commercial on line date of ** ___________ ** for the scrubbers at AmerenUE's Sioux generation plant site, Staff anticipates that the ECRM will reach the statutory cap of 2.5% of AmerenUE's gross jurisdictional revenues in the second recovery period of the ECRM. In essence, if the Commission grants AmerenUE an ECRM in this case, the Commission will be granting AmerenUE another 2.5% increase in customer bills within 16 to 18 months from the effective date of new rates in this rate case. Staff recognizes that, if the Commission approves an ECRM for AmerenUE in this case, AmerenUE could file another general electric rate case where the Sioux scrubbers would be placed in its base rates before the beginning of the ECRM recovery period where the ECRM rates would begin recovering the costs of the Sioux scrubbers.

1. Evaluation Criteria

Guidance for the Commission's exercise of its authority to establish an ECRM is set out both in section 386.266 RSMo. Supp. 2009 and Commission rules 4 CSR 240-3.162 Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements and 4 CSR 240-20.091 Electric Utility Environmental Cost Recovery Mechanisms. These rules became effective August 30, 2009.

The statute gives the Commission the power to in its discretion approve, modify, or reject proposed ECRMs, but only after providing the opportunity for a full hearing in a general rate proceeding – which according to the statute and the Commission's rules may be a general rate increase proceeding. AmerenUE is requesting an ECRM in this rate increase case.

The Commission's authority to authorize rate adjustment mechanisms (which includes fuel adjustment clauses (FACs)) arises from the same section of statute (section 386.266 RSMo. Supp. 2009). Ten of the thirteen subsections of this statute apply to both rate adjustment mechanisms and environmental cost recovery mechanisms. This is the first request for an ECRM; therefore, the Commission has not previously evaluated a proposed ECRM to determine whether or not to approve or establish an ECRM. However, there have been four different rate cases[21] before the Commission in which electric utilities have requested FACs. In the Report and Orders in these rate cases, the Commission provided guidance to parties of the criteria the Commission considers for approval of a fuel adjustment charge. For guidance concerning Staff recommendation to the Commission regarding AmerenUE's request for an ECRM, the Staff chose to utilize the criteria the Commission set out in its most recent Report and Order in which it authorized AmerenUE's fuel adjustment clause (Case No. ER-2008-0318). In that Report and Order, the Commission set out five criteria for determining if fuel and purchased power costs and revenues should be recovered through a fuel adjustment clause. These criteria, made broader for use for any mechanism, follow:

1. Costs are substantial enough to have a material impact upon revenue requirements and the financial performance of the utility between rate cases;

[21] Case Nos. ER-2007-0002 (AmerenUE), ER-2007-0004 (Aquila, Inc., n/k/a KCP&L Greater Missouri Operations Company), ER-2008-0093 (The Empire District Electric Company) and ER-2008-0318 (AmerenUE).

2. Costs are beyond the control of management, where utility management has little influence over experienced revenue or cost levels;

3. Costs are volatile in amount, causing significant swings in income and cash flows if not tracked;

4. The mechanism is needed for the utility to have a reasonable opportunity to earn a fair return on equity; and

5. The mechanism is needed to be able to compete for capital with other utilities that already have a similar mechanism.

Staff looked at each criterion to determine whether or not it would be applicable for determining whether or not the Commission should approve an ECRM for AmerenUE and, if so, whether AmerenUE's circumstances satisfy the criterion for approval of an ECRM.

<u>Criterion 1:</u> Costs are substantial enough to have a material impact upon revenue requirements and the financial performance of the utility between rate cases.

Staff looked at the costs included in AmerenUE's Environmental Compliance Plan[22] in the next four years since, if the Commission allowed an ECRM, AmerenUE would be required to come in for another general electric rate increase within four years. Section 386.266.4(1), RSMo. Supp. 2009. The largest cost in its Environmental Compliance Plan is capital investment for the installation of two wet flue gas desulphurization units (commonly called scrubbers) at AmerenUE's Sioux plant. The estimated cost of this capital addition is ** __________ **, and the scrubbers are scheduled to be completed in ** __________ **. This is substantial enough to have a material impact upon AmerenUE's revenue requirement and its financial performance.

Staff is not convinced that that the additional capital costs and expenses AmerenUE has specified over the next four years, other than the cost of the Sioux scrubbers, are substantial enough warrant the need for an ECRM.

<u>Criterion 2:</u> Costs are beyond the control of management, where utility management has little influence over experienced revenue or cost levels.

The Sioux scrubbers and the other costs (both capital and expenses) in AmerenUE's Environmental Compliance Plan are planned in response to current and probable federal and

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[22] Schedule MCB-E3 of AmerenUE witness Mark C. Birk's direct testimony in this case.

state environmental laws and regulations. AmerenUE management does have some discretion in how and when to meet the regulations and rules, but they are mandates and must be met.

Criterion 3: *Costs are volatile in amount, causing significant swings in income and cash flows if not tracked.*

This criterion does not appear to apply to environmental costs. Staff does not foresee any rules or regulations that would decrease AmerenUE's environmental costs. If an environmental law or regulation is proposed that would cause significant increase in capital outlays, typically the federal and/or state legislation takes into account the fiscal impact and timing of the proposed legislation before approving it. This is currently occurring in the debate on federal cap and trade legislation. Once the magnitude of the impact of this proposed legislation was estimated, there have been a lot of proposed changes to the legislation designed to lessen the fiscal impact of the proposal. Therefore, while environmental costs to meet environmental laws and regulations may be significant, typically the legislation or rules are designed to reduce volatility and do not result in significant swings in utility income and cash flows.

Criterion 4: *The mechanism is needed for the utility to have a reasonable opportunity to earn a fair return on equity.*

When the utility has a significant environmental cost outlay, such as what is required for the Sioux scrubbers, it could have an impact on whether the utility has a sufficient opportunity to earn a fair return on equity. However, traditional ratemaking in Missouri allows a utility to earn the cost of the capital that is incurred during construction through the use of an Allowance for Funds Used During Construction (AFUDC). Since AmerenUE began construction of the Sioux scrubbers in 2006, AFUDC has been accumulating and will continue to accumulate on the funds used for their construction until the scrubbers go into commercial operation, which is on or before the date they become fully operational and used for service.[23] Due to the timing of this rate case, the Sioux scrubbers are not estimated begin commercial operation until a year after the true-up period of this rate case which ends January 31, 2010. Therefore, the Sioux scrubbers cannot be considered fully operational and used for service, and included in AmerenUE's rate base in this rate case.

[23] Recovery of costs of construction in progress is not prohibited until the facility is "fully operational and used for service." Section 3903.135, RSMo. 2000.

Since, in the Staff's view, the other environmental costs in AmerenUE's Environmental Compliance Plan are not are substantial enough to have a material impact upon AmerenUE's revenue requirement, an ECRM would not be needed for AmerenUE to have a sufficient opportunity to earn a fair return on equity absent the Sioux scrubber installation. Under traditional Missouri ratemaking, AmerenUE should time its next rate case to minimize the amount of time between commercial operation of the scrubbers and the inclusion of the scrubbers in rate base.

Criterion 5: *The mechanism is needed to be able to compete for capital with other utilities that already have a similar mechanism.*

Environmental cost recovery mechanisms are not as prevalent as fuel adjustment clauses. Staff has not done an extensive review of all 50 states to see which ones allow environmental cost recovery between rate cases. However, AmerenUE witness Johannes Pfeifenberger, in response to Staff Data Request No. 254, stated:

In early 2005, AmerenUE asked Mr. Pfeifenberger to identify states allowing the recovery of environmental-related capital costs through rate adjustment mechanisms ("RAM"). That research identified eight other traditionally-regulated states that allowed some form of RAM recovery of environmental-related capital expenditures, including: Alabama, Arkansas, Colorado, Florida, Indiana, Kentucky, Minnesota, and Mississippi. In some of these states, environmental operating expenses are also recovered through the RAM, in other states such costs are recovered through fuel adjustment clauses. In addition, three states (West Virginia, Wisconsin, and North Carolina) were found to allow tax-exempt bond financing of environmental projects, and two restructured states (Ohio and Virginia) employ rate riders for recovery of environmental compliance costs. The 2005 environmental RAM research did not cover the entire U.S. and has not been updated since that date; nor is Mr. Pfeifenberger aware of a comprehensive 3rd party survey of such environmental cost riders.

Therefore, an ECRM is not necessary to level the playing field for AmerenUE to compete with other utilities for capital. On the contrary, if the Commission grants it an ECRM, AmerenUE will have an advantage over many utilities.

2. Minimum Filing Requirements

The Staff has found that AmerenUE has met the minimum filing requirements as found in 4 CSR 240-3.162(2).

3. Recommendation

Having an ECRM will enable AmerenUE to begin cost recovery of the cost of the Sioux scrubbers between the effective date of this current rate case and AmerenUE's next general rate case, assuming AmerenUE does not file another rate case immediately on the heels of this one. Staff recommends that the Commission allow AmerenUE to implement an ECRM with the conditions that follow. Some of the items below represent possible material differences between AmerenUE and Staff.

4. Environmental Revenue Requirement

The most material difference between AmerenUE and Staff is the designation of the environmental revenue requirement. Both rules 4 CSR 240-3.162(1)(F) and 4 CSR 240-20.195(1)(D) are clear on the definition of the "base environmental revenue requirement:"

The environmental revenue requirement shall be comprised of the following:

> 1. All expensed environmental costs (other than taxes and depreciation associated with capital projects) that are included in the electric utility's revenue requirement in the general rate proceeding in which the ECRM is established; and
>
> 2. **The costs (i.e., the return, taxes, and depreciation) of any major capital projects whose primary purpose is to permit the electric utility to comply with any federal, state, or local environmental law, regulation, or rule.** Representative examples of such capital projects to be included (as of the date of adoption of this rule) are electrostatic precipitators, fabric filters, nitrous oxide emissions control equipment, and flue gas desulfurization equipment. The costs of such capital projects shall be those identified on the electric utility's books and records as of the last day of the test year, as updated, utilized in the general rate proceeding in which the ECRM is established; (emphasis added)

The base environmental revenue requirement should include the cost of all the major capital projects whose primary purpose is to comply with environmental laws, regulations and rules. This base should be reset every general rate case. The base should be an accumulation of the total environment costs in every account listed by AmerenUE in its ECRM minimum filing requirements.[24]

The Staff has not yet been able to calculate the correct base environmental revenue requirement, but believes that it is closer to $1.29 billion than the $0.56 billion shown in Schedule GSW-E21 of the direct testimony of AmerenUE witness Gary S. Weiss. This belief is supported by information received from the Company regarding classification of environmental costs last determined in 2007.

5. Fully Operational and Used for Service Designation

An ECRM includes the recovery of capital costs in addition to expenses. Significant capital costs, such as the Sioux scrubbers should not be placed in an ECRM for cost recovery until the Commission declares them to be fully operational and used for service. Section 393.135, RSMo. 2000. On the advice of Counsel, it is Staff's position that the fully operational and used for service requirement is still effective for large capital projects that maybe included in an ECRM. Staff has developed a draft of in-service criteria that it proposes it to use for making its recommendation to the Commission of when the Sioux scrubbers are fully operational and used for service. Staff will work with AmerenUE in the further development of these criteria.

Staff will file a recommendation to the Commission when Staff determines the Sioux scrubbers have met the in-service criteria. After the Commission determines the date the Sioux scrubbers become fully operational and used for service, the costs of the scrubbers should be included in additional Plant in Service in the ECRM accumulation period in which the date the Commission determines the scrubbers became fully operational and used for service falls.

6. Accumulation and Recovery Periods

The Commission's ECRM rules allow a maximum of two ECRM-related rate changes in a year. 4 CSR 240-20.091(4)(D). The Staff recommends that the Commission set the ECRM Accumulation Periods and Recovery Periods at six months.

Unlike the statutory language regarding rate adjustment mechanisms (e.g. fuel adjustment clauses (FACs)), section 386.266, RSMo. Supp. 2009, restricts the costs annually recovered by an ECRM to 2.5% of the electric utility's "Missouri gross jurisdictional revenues, excluding

[24] Schedule MCB-E2 of AmerenUE witness Mark C. Birk's direct testimony in this case.

gross receipts tax, sales tax and other similar pass-through taxes not included in tariffed rates, for regulated services as established in the utility's most recent general rate case or complaint proceeding." This adds some complications to an ECRM that do not exist with a FAC. When the Commission makes a final determination on AmerenUE's gross jurisdictional revenues for regulated services, the cap amount will be calculated. This will provide the maximum amount that AmerenUE can recover through an ECRM in a twelve-month period. Six month accumulation and recovery periods will make it easier to determine whether or not AmerenUE recovers more than the cap amount in the twelve months. Staff's proposed timeline for accumulation and recovery periods for the first two years of the ECRM which it recommends the Commission adopt in this case will also be described in Staff's exemplar ECRM tariff sheets that will be filed with the Staff's Class Cost-of-Service and Rate Design direct filing on January 6, 2010.

7. Identification of ECRM Charge on Customers' Bills

To lessen customer confusion regarding the ECRM charge on AmerenUE electric customers' bills, Staff recommends that the Commission require AmerenUE to not use the acronym "ECRM" as shown on the customers' bills and, instead, use the words "Environmental Cost Recovery Adjustment."

Also Staff recommends the Commission require AmerenUE to put a brief explanation of the ECRM on the customers' bills for the first three billing months after the ECRM appears on the bills to help inform AmerenUE's customers regarding the ECRM. Staff recommends that the Commission require AmerenUE to get Commission approval of the explanation that will appear on the customers' bills prior to it appearing on the bills.

8. Additional Submission Requirements

Costs recovered in AmerenUE's ECRM should only be the incremental difference from the amounts in the accounts used in setting the ECRM base in this rate case. Therefore, if AmerenUE seeks to include costs not included in these other accounts as part of an ECRM rate change, the Commission should require AmerenUE to identify the environmental law, regulation or rule that became a requirement after establishment of AmerenUE's ECRM that caused AmerenUE to incur the incremental costs it seeks to include in the ECRM rate change.

In response to the minimum filing requirement of 4 CSR 240-3.162(2)(H)[25] AmerenUE gives an explanation of the costs that shall be considered for recovery in its ECRM and the specific account used for each cost item on its books and records. AmerenUE then states that there may be items that cannot be identified at this time which, if required by environmental law or regulation, will be assigned to the appropriate FERC account. Staff requests that the Commission order AmerenUE to identify with its monthly ECRM reports each and every cost that is not included within those FERC accounts it has already identified and identify the appropriate FERC account where AmerenUE is booking that cost and to identify the new environmental law, regulation or rule that AmerenUE asserts caused it to incur the cost.

Staff also recommends that the Commission order AmerenUE to provide to the Staff and the other parties that receive ECRM monthly and quarterly reports, all updates to AmerenUE's Environmental Compliance Plan with the changes identified from the previous version, within 30 days of an update to the plan.

Staff Expert/Witness: Lena M. Mantle

XII. Other Tariff Items

A. Miscellaneous Tariff Issues – Meter Error

AmerenUE has filed a proposed addition to Tariff Sheet No. 170, General Rules and Regulations, V. Billing Practices, G. Billing Adjustments, 1. Residential, adding section f.:

> f. No corrections to metering data for meter error shall extend beyond the in-service date of the meter discovered to be in error, nor shall any correction be required to extend beyond the date upon which the current customer first occupied the premises at which the error is discovered.

AmerenUE currently has this provision for its Non-Residential Billing Adjustments on Tariff Sheet No. 170.1. UE proposes to apply this rule to both, residential and non-residential customers. There will be a minimal revenue impact due to this proposed rule addition.

Staff accepts AmerenUE's proposed meter error language addition on Tariff Sheet No. 170.

[25] Schedule MCB-E2 of AmerenUE witness Mark C. Birk's direct testimony in this case.

<u>Miscellaneous Tariff Issues</u> – Tariff Sheets Errors

AmerenUE needs to correct the following minor errors on the following proposed tariff sheets:

Sheet No. 68 – text header missing "Rate Based on Monthly Meter Readings"

Sheet No. 68.4, 7th line – remove return command or add spaces between "factor." And "Where"

Staff Expert – William L. McDuffey

C. Voluntary Green Program

1. Summary

In this case, Staff recommends the Commission order AmerenUE to modify its Voluntary Green Program ("VGP" or "program"). Specifically, Staff recommends that the Commission require AmerenUE to prominently post and display on its website a simple, easy to understand, breakdown by percentage of the distribution of each $15 of customer money collected pursuant to the program. In addition, the yearly distribution should be included on all its written promotional information disseminated to potential and existing participants, specifically including the percentage of VGP dollars (1) spent on program administration, (2) spent on program promotion ("education"), (3) retained by AmerenUE, and (4) actually paid to generators of green energy for the acquisition of Renewable Energy Credits or Renewable Energy Certificates ("RECs"). [26]

Staff also recommends that AmerenUE be ordered to include a clear disclaimer that participation in the program will not cause the participants to be delivered "green" electricity, or AmerenUE to purchase green electricity. Staff further recommends that if AmerenUE ties newspaper or other press or industry quotes or excerpts to its Pure Power website or promotional materials, that it also prominently display any applicable corrections to those items. For

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[26] The Center for Resource solutions describes a REC as follows:
"Renewable Energy Certificates (RECs). A REC represents **the non-energy attributes**, including all the environmental attributes, of one megawatt-hour (MWh) of renewable electricity generation. The renewable energy market developed the REC as a tradable commodity **embodying renewable energy attributes that can be sold separately from the underlying electricity**, allowing for a larger and more efficient national market for renewable energy." **(Emphasis added)** (2008 Green-e Verification Report – page 5)

example, AmerenUE should include corrections regarding items containing misleading or false information, such as a statement that program participation results in green electricity being purchased by AmerenUE, or delivered to program participants.

2. Program Description

AmerenUE's Pure Power Program's stated purpose is "expanding the use of renewable resources,"[27] and it is tariffed as the Voluntary Green Program. The stated purpose of the program, according to the tariff is:

> … to provide customers with an option to **contribute** to the further development of **renewable energy technologies." (Emphasis Added)** (Tariff Page 216)

Both the AmerenUE website and the tariff state that the money provided will be spent on either "renewable resources" or on "renewable energy technologies".

While tariffed as the Voluntary Green Program, the program is promoted on AmerenUE's website and elsewhere as "Pure Power." Marketing material states that participating customers are "P.U.R.E.* Genius (*People Using Renewable Energy)." However, participants do not actually get anything special or different in the way of the electrical energy they receive. Participants get the electricity generated by the same sources as customers who choose not to participate. AmerenUE does not purchase green energy as a consequence of program participation.

The money provided by participants is distributed to at least two entities other than those actually producing green energy. RECs are purchased by 3 Degrees and retired on behalf of program participants. Ameren Services retains an administrative fee of $1 per REC, and 3 Degrees retains the remaining money and engages in various activities under contract with AmerenUE.

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[27] AmerenUE's Pure Power Web site / Pure Power FAQs / Question #5
http://www.ameren.com/PurePower/ADC_FAQsPurePower.asp

3. Concerns and Recommendations

Disclosure:

Marketing materials convey the program's primary purpose and activity to be the purchase of RECs from renewable generators. The percentage actually making it into the hands of green energy producers, however, causes Staff concern.

National Renewable Energy Laboratory (NREL) has made a statement that succinctly describes the basis of this concern:

> "Given these conflicting perceptions of green power programs, **utilities may reasonably expect that residential consumers will have a right to know the underlying cost structure of green power pricing programs and an interest in minimizing marketing costs**."[28] **(Emphasis Added)**

Staff's recommendation is that AmerenUE supply the "right to know" information at its website, and in its promotional materials. While Staff is not currently recommending termination of the program, two other state commissions, Florida and Indiana, have referenced

continued on next page

[28] Green Pricing Program Marketing Expenditures: Finding the Right Balance – Page 12

these NREL "right to know" criteria when they terminated "green" programs in their jurisdictions.[29] Staff's recommendation that the Commission require AmerenUE to inform current and potential participants that much of the money is actually going for administration and marketing of the program should enable customers to have better knowledge and more complete information when deciding whether to participate in this program.

AmerenUE's Actual Distribution of Pure Power Collections

For each $15.00 a customer contributes, the distribution of that money is as follows:

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[29] *Florida Program*

The Florida Commission required the termination of Florida Power & Light Company's Sunshine Energy® program when it was discovered that only 20.87% of the money collected was spent on purchases of RECs - 74.14% of the money collected was spent on marketing and other costs. The Florida Commission clearly stated its primary concern with the Sunshine Energy® program when it stated:

> "One concern, however, is the audit's finding that **the vast majority of the program's revenues have been spent on marketing and administrative costs**." (Emphasis added) (Order Terminating Program and Cancelling Tariff / Docket No. 070626-EI/ Order No. PSC-08-0600-PAA-EI/ Sept. 16, 2008 – Page 6)

Indiana Program

The Indiana Commission terminated the Southern Indiana Gas & Electric Company's Vectren Green Power (VGP) program. NREL characterizes the Indiana Commission's actions as follows:

> "In a May 2008 order, the Indiana Utility Regulatory Commission similarly found that a voluntary program proposed by Southern Indiana Gas & Electric Company, while "a laudable effort," **was "apt to be confusing to its customers and … not … in the public interest," based on the contention that "customers are likely to believe they are purchasing renewable energy by enrolling in the VGP [sic] program, when in fact they are paying Vectren South to retire the RECs that are associated with the renewable energy they have already paid for in their electric bill … with the proceeds going primarily to pay for VGP program administration costs**." (emphasis added) (Green Pricing Program Marketing Expenditures: Finding the Right Balance – Page 2) http://www.nrel.gov/docs/fy09osti/46449.pdf
>
> Further, the Indiana Order Cause NO. 43259 SI included the following:
>
> Consequently, instead of purchasing renewable energy, VGP p**articipants are paying for Vectren South to advertise the benefits of renewable energy to its customers.** In addition, while Vectren South asserts the VGP participants will benefit from the program by being able to support participation and growth in the renewable energy market through the retirement of the BCW RECs, **customers can already easily receive a similar benefit, at a cost that is likely to be less than that of participation in the VGP program, by purchasing RECs in the marketplace. (**emphasis added**) (**Order of the Indiana Utility Regulatory Commission, Cause # 43259 S1, May 28,2008, Page 7)

Calendar Year 2008[30]

CUSTOMER CONTRIBUTES	$15.00		
AMERENUE RETAINS	$ 1.00		
3DEGREES RECEIVES	$14.00		
		3DEGREES RECEIVES	$14.00
		Reported Expenses	
		Average Wholesale Cost per REC	** ____ **
		Average Education	** ____ **
		Average Administration	** ____ **
			** _____**

- Only ** ______ ** of the monies collected went to the wholesale purchase of RECs

- The composite of AmerenUE's administrative fee and 3 Degree's Education & Administration charges, (non-REC) costs comprised ** ______ ** of total collections. (AmerenUE's administrative fee – 6.67%, 3 Degree's Education – ** ______ **, and 3 Degree's Administration ** ______ **)

Staff recommends that the Commission order AmerenUE to prominently post this information until AmerenUE can post up-dated calendar-year 2009 information. Staff would note that AmerenUE has supplied the following information for "Q2 2009" – meaning through June 2009:

continued on next page

[30] AmerenUE's response to Staff's DR 115.

NP

Q2 2009

CUSTOMER CONTRIBUTES	$15.00
AMERENUE RETAINS	$ 1.00
3DEGREES RECEIVES	$14.00

3DEGREES RECEIVES	$14.00
Reported Expenses	
Average Wholesale Cost per REC	** ____ **
Average Education	** ____ **
Average Administration	** ____ **
	** ____**

- Only ** ______ ** of the monies collected went to the wholesale purchase of RECs

- For both AmerenUE's administrative fee and 3 Degree's education & administration charges, the composite of these internal (non-wholesale REC) costs comprised ** ______ ** of total collections. (AmerenUE's administrative fee – 6.67% / 3 Degree's Education – ** ______ ** / 3 Degree's Administration ** ______ **)

While this is an improvement over past years, the six-month period still shows the various non-REC costs to be greater than the money used to purchase RECs. NREL has reported nationally that **a median of 18.8 percent of the money that utilities raised in voluntary programs goes into promotion and marketing**.[31]. In addition to falling far short of the national median, the Pure Power Program's distribution is not consistent with representations that program participation is primarily focused on supporting green energy. As reported by AmerenUE for calendar-year 2008, only ** ____ ** of the money-given actually went for the purpose of acquiring RECs. To provide appropriate disclosure to customers, Staff recommends that AmerenUE be required to post the distribution information cited above.

[31] Green Pricing Program Marketing Expenditures: Finding the Right Balance – Executive Summary – Page V

False or Misleading information:

A repeated theme of AmerenUE's program website is that program contributions go for the acquisition and retirement of RECs. Stating the money is going to acquire RECs conveys that the lion's share, presumably at least 50%, of the money given does go for the stated purpose.

The program slogan **"Pure Power is P.U.R.E. Genius!* (***People Using Renewable Energy)[32]" is clearly misleading. AmerenUE does nothing to acquire "green power" for either Pure Power participants, or AmerenUE's customer base – as a whole. Using the "**P.U.R.E.**" acronym indicates usage of renewable energy will occur as a consequence of program participation – which is simply not true.

Another example of where the website implies actual electricity is being purchased is the following:

<u>"Pure Power—My Home</u>

> Residential and small business customers can also participate in Pure Power by indicating **how many "blocks" they wish to purchase—$15.00 per each 1,000 kilowatthour (kwh) block—**which equals one Renewable Energy Certificate from local renewable sources that will be added to the Midwest energy pool"[33] **(Emphasis Added)**

This quote makes it sound as if the contributor is purchasing blocks of electricity.

The Pure Power newsletters contain similar misleading statements. There are quotes that indicate Pure Power equates to "green" electricity. For example:

> "UE's Pure Power complements Proposition C by giving customers the choice to support new renewable energy sources for 100% of their energy use **today**."[34]

Participation in the program has no direct impact on any customer's energy use. There is also an issue of how much, if any, of the ** ____ ** contribution is actually reinvested in additional "green" production. While the widely-held assumption is that the REC wholesaler will reinvest whatever dollars received in further "green" development, there is no requirement,

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[32] AmerenUE's Pure Power Web site / Pure Power Home http://www.ameren.com/PurePower/ADC_Default.asp

[33] AmerenUE's Pure Power Website / Information for AmerenUE Customers http://www.ameren.com/PurePower/ADC_MorePurePowerAmerenUE.asp

[34] Ibid

nor monitoring, of what the REC wholesaler actually does with the ** ____ ** of the total Pure Power contribution that is received in payment for the RECs.

Another AmerenUE newsletter included the following:

> "On Wednesday, April 22nd, when the Cardinals meet the Mets, they'll reduce their carbon "cleat" print by fully offsetting game day electricity at the stadium with clean, renewable energy, compliments of AmerenUE's Pure Power."[35]

The electricity for the Cardinals April 22 game was no more "environmentally friendly" than the electricity used in any other game, or by any non-contributing customer. The Cardinals did cause RECs to be purchased and retired equivalent to the amount of fossil-fuel electricity that was utilized in the game. The Cardinal's contribution will go for the purchase of future RECs that represent the past attributes of already-utilized electricity at the time the REC is purchased, but that is all.

Yet another misleading statement is found on the application form that customers use to sign-up for Pure Power:

> At least half of the Pure Power demand **will be met by new renewable generators** located within Missouri and Illinois." (Emphasis Added)

Renewable generators generate electricity. This statement indicates that those who participate in the program get "green" electricity in return.

Although there are some disclaimers that the customer is not buying actual electricity on the website, these statements by AmerenUE, such as those quoted above, imply or insinuate that green electricity is being supplied to the participant as a consequence of participation.

AmerenUE also provides links on its website to at least four newspaper stories that contain false or misleading information regarding Pure Power. On March 14, 2008, the Webster – Kirkwood Times ran a story titled "Webster Grove Residents Embrace 'Pure Power,'" which stated that:

> AmerenUE supplies electricity from renewable energy facilities to those enrolled in the Pure Power program.

and

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[35] AmerenUE's Pure Power Website / P.U.R.E.*, No Spin / Newsletter http://www.ameren.com/PurePower/ADC_PurePowerNewsletter1Q09.asp

NP

> Seventy-five percent of Pure Power's energy comes from wind farms.

While AmerenUE may not control what the Webster – Kirkwood Times runs in its paper, it does control what links it provides on the Pure Power website.

A The Washington Missourian Article linked by AmerenUE, "A Pure Way to Power Your Home, Business"[36] states the following:

> The Pure Power program is designed to get a minimum of **75 percent of its energy from wind farms** and up to **25 percent from other renewable energy facilities** said Bambini.[37] **(**Emphasis Added**)**
>
> Right now **the program is getting 100 percent of its power from wind**, specifically the Bluegrass Ridge Wind Farm in Gentry County in Northwest Missouri, Bambini noted. But next month, **the program will begin drawing energy from a landfill gas plant in Springfield** where the methane gas that comes off of trash is converted into energy. **(**Emphasis Added**)**

While there are references to the purchase of RECs elsewhere in the story, these statements convey that participation in Pure Power equates to the consumption of "real" green electricity. If the quotes attributable to Ms. Bambini, a 3 Degrees representative, are reported accurately, these statements are misleading in that the reality is that no known percentage of green electricity is actually being used as a consequence of program participation.

Stlcommercemagazine published an article that is linked from AmerenUE's website, titled *GREEN ENERGY- AmerenUE's Renewable Energy Program Benefits Both Customers and Region*[38] that gives every indication that those who subscribe to Pure Power, get "real" green electricity as a consequence of participation. The story contains the following:

> "A minimum of 75 percent of **Pure Power's renewable energy** comes from wind power and up to 25 percent from a blend of other renewable sources. At least half the supply is generated in Missouri and Illinois, and the rest from other parts of the Midwest."

The St. Louis Post-Dispatch, on August 7, 2008, published a story titled *Clayton makes a Pure Power play - City signs up for program encouraging the use of renewable energy*[39]. The

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[36] by Karen Cernich 05/16/2008
[37] Cindy Bambini is a Senior Manager with 3 Degrees
[38] written by Laurie Burstein / April 2008 Publication
[39] Author: Margaret Gillerman

story indicates that the city will be getting green power as a consequence of its participation even though there is reference to RECs in the story. It says the following:

> “City signs up for program encouraging the **use of renewable energy**.”
>
> **“The use of renewable energy** helps offset the use of electricity from coal and other, non-renewable sources.” (Emphasis added)

These stories containing clear misperceptions and misrepresentations remain available from AmerenUE’s website - with no disclaimer or clarification.[40] If AmerenUE was concerned with presenting accurate information, it should at least attempt to rectify any misconceptions contained in these stories, not perpetuate the misconceptions by referencing them on its website, un-clarified. Further, the content of these stories is likely indicative of how Pure Power is understood by the general public, due to AmerenUE’s above-cited misinformation.

Staff recommends that the Commission require AmerenUE to prominently display on the Pure Power website and incorporate into its written “educational” and promotional materials the following:

> Contributions to Pure Power **do not directly result in the purchase “green” electricity**. Approximately ** ______** of contributions are spent on the acquisition and retirement of RECs. Although the purchase of a REC may stimulate demand for additional renewable energy, RECs represent the positive attributes of energy generated in the past and purchase of RECs does not cause delivery of green energy directly to any AmerenUE ratepayer.

continued on next page

[40] Pure Power News / http://www.ameren.com/PurePower/ADC_PurePowerNews.asp

NP

4. Conclusion

A November 17, 2009 New York Times article – *Paying Extra for Green Power, and Getting Ads Instead,* by Kate Galbraith – reiterates many of Staff's concerns that RECs are not the best avenue to support growth of renewable energy.[41] At this time, Staff is not recommending that AmerenUE be required to terminate the Pure Power Program. However, Staff encourages the Commission to consider the following NREL guidelines:

> "In light of recent criticisms, programs should prioritize the provision of thorough consumer information in multiple forms, including **complete explanations of RECs, how renewable energy is developed and delivered, and how participant funds are spent." (Emphasis Added)**
>
> "**Improved transparency should start with better information to program participants about what projects their premiums support**. **Better data about expenditures will help** regulatory commissions better understand the complexities of the industry, such as the cost risks associated with REC markets, for which price volatility has been significant in certain U.S. regions. **Regulators should not merely gather more information about program budgets; they should evaluate marketing expenditures in light of the full range of their purposes and benefits."[42] (Emphasis Added)**

---

[41] The story documents that there are other parties who question the value of programs like Pure Power. At a minimum, it states that there are opposing views as to the value of "green" programs. Quotes within the story are as follows:

> But some advocates for electricity consumers argue that the payments make little difference. Matthew Freedman, a staff lawyer with the Utility Reform Network, a ratepayer advocacy group in California, said the short-term nature of voluntary green power commitments meant that they were often meaningless on long-term projects like new wind or solar farms.
>
> There is very little evidence to suggest that customer subscriptions have resulted in any new additions of renewable power," Mr. Freedman said.
>
> But in the back of some people's minds, there may be another issue: Do these programs really cause more renewable energy projects to get built? The government has looked at the question, and says it is difficult to draw an overall conclusion. Its experts say they believe that some green power programs work better than others.
> (See Attachment 1, within Appendix 5)

[42] Green Pricing Program Marketing Expenditures: Finding the Right Balance – "Notice" Sheet" http://www.nrel.gov/docs/fy09osti/46449.pdf

These guidelines are consistent with Staff's recommendations that AmerenUE provide sufficient and accurate information to their customers to enable customers to make informed decisions about the value and nature of Pure Power.

Staff Expert/Witness: Michael J. Ensrud

Appendices

Appendix 1: Staff Credentials

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

Appendix 3: Support for Demand-Side Management Resource Status - Adam C. McKinnie and John a. Rogers

Appendix 4: Staff Recommended Depreciation Rates - Arthur W. Rice

Appendix 5: Support for Voluntary Green Program - Michael Ensrud

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service	)))	Case No. ER-2010-0036

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 in pages 48-49 and 74-75; 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 16th day of December, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	)))	Case No. ER-2010-0036

AFFIDAVIT OF KOFI AGYENIM BOATENG, CPA, CIA

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 in pages 47, 50-54, 60, 61, 63-65, 78-83, 87-89; 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 Agyenim Boateng, CPA, CIA

Subscribed and sworn to before me this 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	)))	Case No. ER-2010-0036

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 in pages 49-50, 75-77 and 80; 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 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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D Suzie Mankin

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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 in pages 58 and 59; 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 16th day of December, 2009.

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Callaway County
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Susan L Sundermeyer
Notary Public

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AFFIDAVIT OF DAVID ELLIOTT

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

David Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 71 and 72; 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 Elliott

Subscribed and sworn to before me this 16th day of December, 2009.

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AFFIDAVIT OF MICHAEL J. ENSRUD

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

Michael J. Ensrud, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 123 - 134; 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 J. Ensrud
Michael J. Ensrud

Subscribed and sworn to before me this 16th day of December, 2009.

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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 in pages 38-39, 47-48, 83-91; 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 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 54 - 58 and 60; 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.

Manisha Lakhanpal

Manisha Lakhanpal

Subscribed and sworn to before me this 16th day of December, 2009.

Susan L Sundermeyer

Notary Public

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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 in pages 72 - 74; 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 16th day of December, 2009.

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Callaway County
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Susan L Sundermeyer
Notary Public

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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 in pages 68 - 70; 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 16th day of December, 2009.

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Susan L. Sundermeyer
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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 in pages 62 and 63; 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 16th day of December, 2009.

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September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer
Notary Public

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AFFIDAVIT OF WILLIAM L. McDUFFEY

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

William L. McDuffey, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 122 - 123; 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.

William L McDuffey
William L. McDuffey

Subscribed and sworn to before me this 16th day of December, 2009.

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Susan L Sundermeyer
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AFFIDAVIT OF ADAM McKINNIE

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

Adam McKinnie, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 40 - 42; 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.

Adam McKinnie

Subscribed and sworn to before me this 16th day of December, 2009.

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Susan L. Sundermeyer
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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 in pages 4 through 38; 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 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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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 in pages 1-3, 42-43, 48, 86-87, 89-93; 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 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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D Suzie Mankin
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AFFIDAVIT OF ARTHUR W. RICE, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Arthur W. Rice, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 94 - 105; 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.

Arthur W Rice

Arthur W. Rice, PE

Subscribed and sworn to before me this 18th day of December, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

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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 in pages 43-47 and 105-111; 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 16th day of December, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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Callaway County
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Susan L Sundermeyer

Notary Public

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AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 105 - 112; 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 C. Roos

Subscribed and sworn to before me this 16th day of December, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
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Susan L. Sundermeyer
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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 in pages 113 and 114; 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 16th day of December, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
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Susan L. Sundermeyer

Notary Public

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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 in pages 54-56 and 59-60; 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 16th day of December, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
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Commission #06942086

Susan L. Sundermeyer

Notary Public