MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2010-0130

Jefferson City, Missouri
February 26, 2010

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COST OF SERVICE REPORT

I. Executive Summary

The Staff has conducted a review in Case No. ER-2010-0130 of all cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise The Empire District Electric Company's ("Empire" or "Company") Missouri jurisdictional revenue requirement. This audit was performed in response to Empire's application to increase its Missouri jurisdictional retail rates by approximately $68.7 million, exclusive of applicable gross receipts, sales, franchise or occupational fees or taxes, filed on October 29, 2009.

The Staff's revenue requirement audit of Empire is based upon a test year of the twelve months ending June 30, 2009. The Staff is using a test year update period ending December 31, 2009. Major elements of the revenue requirement calculation for Empire were measured through December 31, 2009, in the Staff's case. The Staff's audit results for Empire at the midpoint of its return on equity range (ROE) of 9.40% would be a rate increase of $7,724,759. In addition, the results of the Staff's regulatory plan amortization calculation would be a further increase in revenue requirement of $60,536,325, for a combined revenue requirement of $68,261,084.

Impact of Staff's Revenue Requirement on Each Retail Rate Customer Class

The impact of the Staff's recommended revenue requirement for each retail rate customer class will be proposed in the Staff's rate design testimony that is to be filed on March 9, 2010.

II. Background of Empire

Empire is a Kansas corporation providing electrical utility services in Missouri, Kansas, Arkansas and Oklahoma. Empire also provides water utility services and an affiliated company operates a natural gas distribution business, both in Missouri. Empire serves approximately 167,600 retail electric customers throughout its system of which approximately 148,300 are Missouri customers.

In 2006, the Missouri Public Service Commission ("Commission") approved Empire's acquisition of the Missouri natural gas distribution operations of Aquila, Inc. ("Aquila"). The gas distribution business is operated by Empire through its wholly owned subsidiary, The Empire District Gas Company.

Empire also provides non-regulated fiber optics services through its wholly-owned subsidiary, EDE Holdings, Inc.

Empire last sought to change its Missouri jurisdictional electric retail rates in Case No. ER-2008-0093. In its Order dated August 9, 2008 in that proceeding, the Commission granted Empire a total net increase in rates of $22,040,395. Of that amount, $27,745,475 was granted through a traditional revenue requirement approach, with an offsetting negative regulatory plan amortization result of $5,705,080 against the increased traditional revenue requirement increase amount of $27,745,475 awarded in the form of a "regulatory plan amortization." These amortizations will be described in more detail later in this Cost of Service Report ("Report").

III. Test Year/Update Period/True-Up

Though Empire filed its case based upon a June 30, 2009, test year, it made adjustments to its case to reflect the impact of several material events it expected to occur through the summer of 2010. The Staff, in its filing "Staff Response to Order, Directing Notice, Suspending Tariff, Setting Hearings, and Directing Filing," dated November 30, 2009, agreed with Empire's proposed test year of the twelve months ended June 30, 2009, and in addition proposed a test year update period in this case for the six months ending December 31, 2009. In addition, the Staff proposed a true-up period of the four months ending April 30, 2010 in its "Staff's Proposed Procedural Schedule and Other Proposed Procedures" filing of January 15, 2010.

The parties to this proceeding have reached an agreement on test year, test year update period and true-up matters, and a joint filing was made with the Commission on February 25, 2010 setting forth these agreements The joint filing provided for a test year of the twelve months ending June 2009, a test year update period of the six months ending December 2009, and a true-up period of the three months ending March 2010.

For purposes of the true-up audit, the Staff proposes to update through March 31, 2010 the following items: plant in service; depreciation reserve; other rate base components; payroll expense; payroll-related benefits; fuel and purchased power costs; depreciation and amortization expense; rate case expense; related income tax effects; the customer growth annualization for revenues; and rate of return/cost of capital.

The true-up audit would also potentially include costs associated with Empire's share of the Plum Point unit incurred through March 31, 2010, under the terms of the Stipulation and Agreement filed February 25, 2010. However, Plum Point investment will only be reflected in rate base if the unit is declared to be in-service as provided in the Stipulation and Agreement.

IV. Major Issues

The following are the major differences in traditional revenue requirement that exist between the Staff and Empire based on their respective direct filings. A brief explanation of each item follows:

Iatan 2 – Empire's direct filing reflected the projected capital costs and operating costs of its share of the Iatan 2 generating unit. The Staff has not included any costs of the Iatan 2 generating unit in its case as this unit is not yet in-service. Since the time of Empire's direct filing, the projected in-service date for this unit has been pushed back to the fall of 2010. Both Empire and the Staff agree that the costs of the Iatan 2 generating unit will not be reflected in Empire's rates in this proceeding.

Plum Point – Empire's direct filing reflected the projected capital costs and operating costs of its share of the Plum Point generating unit, as well as the expenses associated with a purchased power agreement Empire entered into to obtain energy from this unit. The Staff has not included any costs of the Plum Point unit in its case, as this unit is not yet in-service. Empire projects that the Plum Point unit will become operational by the end of July 2010.

Return on Equity (ROE) – The Staff has recommended a 9.40% ROE at the midpoint. Empire is recommending an 11.0 % ROE. This issue is addressed in detail in the Section V of this Report.

Fuel and Purchased Power – The Company adjusted its test year fuel/purchased power expense to match the level allowed in base rates in its last general rate proceeding in Missouri, Case No. ER-2008-0093. The Staff chose to adjust test year fuel/purchased power expense to reflect Empire's actual fuel/purchased power costs through the end of the test year update period, December 31, 2009. This analysis resulted in an adjustment to decrease test year fuel/purchased power expense in total. A primary reason for the decrease in fuel/purchased power expense is lower natural gas prices in the Staff's case than the gas costs experienced by Empire during the test year.

Incentive Compensation – The Staff has recommended a disallowance of incentive compensation paid Empire employees, including executive management, related to an earnings goals and discretionary bonuses which are unsupported by any well defined goals with tangible benefits to ratepayers. Staff's position is consistent with the Commission's decision on this issue in Empire's recent rate cases. The Company proposed no adjustment to its test year incentive compensation expense.

Cash Working Capital – Both the Company and the Staff are sponsoring lead/lag schedules in this case to determine Empire's required cash working capital allowance in rate base. There is a significant difference in the results of the two lead/lag studies, based largely upon different conclusions regarding appropriate computation of the "collection lag" component of the overall revenue lag, and of the expense lags associated with Empire's fuel and purchased power expenses.

There are various other issues between the Staff and Empire based upon their respective direct filings which appear to be of lower dollar magnitude. These issues are discussed in this Report as well.

Effect of Stipulation and Agreement – The Staff has entered into an agreement, filed February 25, 2010, with Empire and other parties to this proceeding, which, among other things:

a. Acknowledges that Empire does not seek to recover in the rates resulting from the instant case the costs associated with its investment in Iatan 2;

b. Acknowledges that this case is not the "Rate Filing" called for in Section III.D.7. of the Empire Experimental Regulatory Plan Stipulation and Agreement, Case No. EO-2005-0263;

c. Provides that the signatory parties will support "Construction Accounting" for certain of Empire's investment in Iatan 1 environmental upgrades / air quality control systems ("ACQS"), Iatan 2, Iatan common plant, and Plum Point for the periods and as specified in the attached Non-Unanimous Stipulation and Agreement;

d. Provides that questions of prudency related to Iatan 1 Environmental Upgrades (ACQS), Iatan 2, Iatan common plant and Plum Point will be addressed in Empire's next general rate case proceeding.

Staff Expert: Mark L. Oligschlaeger, Sections I, II, III and IV

V. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return ("ROR") of 7.85 percent to 8.33 percent for The Empire District Electric Company (Empire or Company). Staff's ROR recommendation is based on a recommended return on common equity ("ROE") of 8.90 percent to 9.90 percent (midpoint 9.40 percent) applied to Empire's December 31, 2009, common equity ratio of 47.38 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 has done in other recent electric utility rate cases, Staff decided to deviate from its previous 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 used the actual, consolidated capital structure of Empire as of December 31, 2009, which includes all of Empire's utility and non-utility operations, as the basis for its capital structure recommendation. The Staff's resulting capital structure consists of 47.38 percent common equity, 3.84 percent preferred stock, and 48.79 percent long-term debt. Schedule 7 in Appendix 2 to this Report presents Empire's capital structure and associated capital ratios. Staff's embedded cost of long-term debt of 6.75 percent is based on information provided by Empire in response to Staff Data Request No. 0201.1. Staff's embedded cost of long-term debt is slightly lower than that provided by Empire because Staff decided to disallow $1.6 million of debt expenses associated with Empire's choice to amend its mortgage bond indenture in order to allow it to maintain its current dividend per share of $1.28. Staff subtracted this amount ($1.6 million) from Empire's cost of debt calculation for the period ending December 31, 2009.

Staff has prepared two (2) attachments and twenty two (22) 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 22. 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*).[1] 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.[2]

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

[1] ***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).
[2] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

> 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.[3]

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 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 estimating the cost of common equity.[4] 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.[5] The CAPM is

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[3] ***Hope,*** *supra*, 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345 (citations omitted).
[4] Frank K. Reilly and Keith C. Brown, *Investment Analysis and Portfolio Management*, Fifth Edition, The Dryden Press, 1997, p. 438.
[5] Zvie Bodie, Alex Kane and Alan J. Marcus, *Essentials of Investments,* Richard D. Irwin, Inc. 1992, p. 11.

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 Conditions

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 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 use 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 and has yet to declare an end date to the recession). 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),*[6] about the Federal Reserves' Federal Open Market Committee meeting on January 26 and 27, 2009:

> The Federal Reserve offered a slightly rosier economic outlook and reaffirmed it would stop buying mortgages in March…
>
> The Fed's policy-making arm, the Federal Open Market Committee, said it would continue to keep interest rates near zero for an "extended period," meaning at least several more months…
>
> The economy has "continued to strengthen" and business spending is "picking up," the Fed said. It tweaked its outlook, saying the recovery would be "moderate for a time." Since April, the Fed had been saying economic activity would be "weak for a time." The changes indicated officials believed a recovery was sustainable but not brisk.
>
> The slightly improved outlook suggests rate increases are closer, though not likely until the second half of the year at the earliest. High unemployment or slowing inflation could put off rate increases even longer.

Although the U.S. economy growth increased at an annual rate of 5.7 percent in the fourth quarter of 2009, 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, during the Federal Reserve's meeting in January, for the first time in a year, there was one vote against the action of continuing to keep interest rates near zero. This is a sign of dissension that the Fed needs to raise the Fed Funds rate sooner rather than later. Although the Fed's monetary policy typically focuses on the level of short-term rates, the rate of economic 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

[6] Jon Hilsenrath, "More Upbeat Fed Keeps Rates Low," *The Wall Street Journal*, January 28, 2010, p. A6.

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 part of 2009. However, these rates have since started to return to levels more consistent with recent years. As of January 2010, the yield on 30-year T-bonds averaged 4.60 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 a historical high of 400 basis points in December 2008 (see Schedule 4-4). As of December 2009, the average utility bond yield had dropped considerably to an average of 5.86 percent. As a result, the spread between the utility bond yields and 30-year T-bond yields decreased to 137 basis points in December 2009, approximately 34% of the spread reached last December. The current 137 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 5.86 percent represents a decrease of 194 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 December 2009, this spread was 47 basis points according to the January 2010 *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 December 2009 this spread was 27 basis points. This results in a spread of 74 basis points between an "Aa" rated utility and a "Baa" rated utility. While this represents a 64 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 February 5, 2010, issue of the *Value Line Selection and Opinion*, the yield on "BBB" rated utility bonds was 6.32 percent as of January 27, 2010. Based on the 30-year T-bond yield of 4.56 percent as of the same day, the spot-yield spread was 176 basis points. The spread has dropped by 350 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 January 15, 2010, issue of *The Value Line Investment Survey: Selection & Opinion*, for the fourth quarter of 2009 the Dow Jones Industrial Average ("DJIA") increased by 7.4 percent, the Standard & Poor's ("S&P") 500 increased by 5.5 percent, the NASDAQ Composite Index ("NASDAQ") increased by 6.9 percent, and the Dow Jones Utility Average ("DJUA") increased by 5.5 percent. According to the same publication, for the twelve months ended December 31, 2009, the DJUA increased by 18.8 percent, the S&P 500 increased by 23.5 percent, the NASDAQ composite increased by 43.9 percent, and the DJUA increased by 7.3 percent.

It is noteworthy that the DJUA has generally lagged the other indices over the past year. It is not surprising that other indices have generally outperformed the DJUA over the past year considering that investors may have been expecting an improvement in the economy. However, comparing the indices over the fourth quarter indicates that investors may be becoming more defensive again. 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. Only three of Staff's comparable companies are included in the fifteen companies that comprise the DJUA. These three companies are American Electric Power Co., PG&E Corp., and Southern Company, Inc. Therefore, Staff does not consider the DJUA as a whole to be a good proxy group for Empire. 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 3.4 percent for the fourth quarter of 2009, which is a less than the 5.5 percent increase for the DJUA. The Value Line Utilities Group increased by 5.3 percent for the twelve months ended December 31, 2009, compared to the DJUA's increase of 7.3 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 1.80 percent for 2010, 2.50 percent for 2011 and 2.80 percent for 2012. The

Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2010-2020,* January 2010, forecasts an inflation rate of 2.40 percent for 2010, 1.30 percent for 2011, and 1.20 percent for 2012 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury bills, are estimated to be 0.60 percent in 2010, 2.00 percent in 2011, and 3.00 percent in 2012 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.50 percent in 2010, 5.00 percent in 2011, and 5.10 percent in 2012.

The most recent weekly rate for three-month U.S. Treasury bills was 0.11 percent (see Schedule 5). The most recent weekly rate for long-term Treasury bonds was 4.62 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 increase by 2.20 percent in 2010, increase by 3.10 percent in 2011, and increase by 3.20 percent in 2012. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2010-2020,* January 2010, stated that real GDP is forecasted to increase by 2.20 percent in 2010, increase by 1.90 percent in 2011, and projected to increase by 4.60 percent in 2012 (see Schedule 5).

The Value Line Investment Survey: Selection & Opinion, February 5, 2010, stated the following in its Economic and Stock Market Commentary:

> **The U.S. economy appears to be getting out of the gate slowly this year.** True, a business recovery looks to be securely in place. (The National Bureau of Economic Research – the widely accepted arbiter on the timing of the business cycles – has yet to rule on the downturn's conclusion, although we think it will soon declare that the recession ended in last year's third quarter.) However, even assuming that we are in a sustained expansion, this presumptive up cycle has little conviction, with recent statistics on sales of both new homes and existing residences, weekly jobless claims, and durable goods orders all failing to strengthen the case for a vigorous business recovery.
>
> **We expect little momentum to build in the months to come,** as we are likely to continue grappling with spotty housing demand, tight credit, high consumer debt burdens, wealth depletion (from falling home prices and earlier stock market losses), and lower tax revenues at the state and local levels. This latter shortfall may well restrain the spending needed to create jobs. A stronger inventory cycle, as businesses continue to slow the rate of inventory reduction and likely gains in retail spending (buoyed by a

firming in consumer confidence) and business investment should yield sufficient overall strength to keep the economy growing at an average rate of 2.5% or so, in 2010, however.

A more inclusive expansion is likely to get under way in 2011. By that time, better housing demand and stronger home prices should be in place, helping to create the jobs and wealth needed to put the economy on stronger ground.

Meanwhile, the short-term focus is largely on earnings, as Corporate America releases data for the fourth quarter of 2009. Overall, the reports have been quite positive from a profit standpoint, with results that are often exceeding expectations. The revenue picture is murkier, though, with the failure to meet bloated expectations in some high-profile cases leading to weakness in the affected stocks.

Overall, equities have stumbled a bit after a run of successively higher highs. Worries about possible toughened banking regulations and economic policies in general, fears about revenue growth, and concerns about valuations have all contributed to recent selloff in equities.

Conclusion: We think the pullback has been constructive in removing a little of the market's earlier froth. 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.

D. Overview of The Empire District Electric's Operations, Financing and Staff's Proposed Approach for Estimating Empire'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 Empire's Form 10-K filing with the Securities and Exchange Commission ("SEC") for the 2009 calendar year provides a good description of Empire's current business operations:

> We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. In 2009, 87.5% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 11.5% from our gas segment, and 1.0% from our other segment. The territory served by our electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal economic activities of these areas include light industry, agriculture and tourism. Of our total 2009 retail electric revenues, approximately 89.1% came from Missouri customers, 5.1% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers.
>
> We supply electric service at retail to 121 incorporated communities as of December 31, 2009, and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 53% of our electric operating revenues in 2009 were derived from incorporated communities with franchises having at least ten years remaining and approximately 17% were derived from incorporated communities in which our franchises have remaining terms of ten years or less. Although our franchises contain no renewal provisions, in recent years we have obtained renewals of all of our expiring electric franchises prior to the expiration dates.

Our electric operating revenues in 2009 were derived as follows:

Residential	41.6%
Commercial	31.4
Industrial	15.2
Wholesale on-system	4.2
Wholesale off-system	3.3
Miscellaneous sources*	2.7
Other electric revenues	1.6

*primarily public authorities

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2009 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2009. Our gas operations serve customers in northwest, north central and west central Missouri. We provide natural gas distribution to 44 communities and 310 transportation customers as of December 31, 2009. The largest urban area we serve is the city of Sedalia with a population of over 20,000. We operate under franchises having original terms of twenty years in virtually all of the incorporated communities. Twenty-four of the franchises have 10 years or more remaining on their term. Although our franchises contain no renewal provisions, since our acquisition, we have obtained renewals of all our expiring gas franchises prior to the expiration dates.

Our gas operating revenues in 2009 were derived as follows:

Residential	63.1%
Commercial	27.1
Industrial	3.6
Other	6.2

No single retail customer accounted for more than 4% of gas revenues in 2009.

Our other segment consists primarily of our fiber optics business. As of December 31, 2009, we have 89 fiber customers.

2. *Credit Quality*

Empire's current S&P corporate credit rating of "BBB-" is only one notch above "junk" status. The following is an excerpt from a January 28, 2010, S&P credit-rating report on Empire:

> The ratings on Joplin, Mo.-based utility Empire District Electric Co. reflect a strong business risk profile (business risk profiles are categorized as 'excellent' to 'vulnerable') and an aggressive financial profile

> (financial profiles are ranked from 'minimal' to 'highly leveraged') that will remain under stress due to an onerous construction program that focuses on new generation sources and environmental compliance. Accordingly, continued conservative financing and the company's ability to control costs and manage its regulatory risk will be essential to support key financial metrics at levels suitable for investment-grade ratings.
>
> Empire's business risk profile benefits from a diverse service territory with limited industrial concentration (approximately 15% of total retail load) and from a cost-conscious management team. Although sales have declined and customer growth is at a very low rate, the service area economy remains healthier than other regions in the country. Importantly, Empire has sold virtually all of its riskier unregulated businesses due to financial underperformance. These characteristics are tempered by generation needs and an historically challenging regulatory environment in Missouri, which appears to be becoming more responsive. Nevertheless, Empire's financial performance will continue to be pressured due to rising costs and heavy spending for its construction program. The Company's capital expansion plan revolves around its ownership interest in the Iatan 2 (expected completion recently slipped two months into the fall of 2010) and Plum Point (slated in-service date July 2010) coal-fired stations and on air quality control systems for its investment in Iatan 1.

Moody's also rates Empire and its debt. Moody's currently assigns a "Baa2" corporate credit rating to Empire.

3. Capitalization

> Schedule 6 presents Empire's calendar year-end historical capital structures in dollar and percentage terms for the past five years. Empire's equity ratio declined in 2008 compared to 2007. This decline is caused mainly by Empire's issuance of long-term and short-term debt. In 2009, compared to 2008, Empire's equity ratio increased. This increase is caused mainly by Empire's issuance of common equity in 2009.

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

As explained earlier in the report, the capital structure Staff used for this case is Empire's capital structure on a consolidated basis as of December 31, 2009. Schedule 7 presents Empire's capital structure and associated capital ratios. The resulting capital structure consists of 47.38 percent common stock equity, 48.79 percent long-term debt and 3.84 percent preferred stock.

The amount of long-term debt outstanding as of December 31, 2009, was $618,007,745 and includes current maturities due within one year. The amount of long-term debt in the capital structure is shown on Schedule 7.

The amount of Empire's preferred stock outstanding on December 31, 2009, was $48,638,468 as shown on Schedule 7. Empire's current preferred stock is in the category of "trust-preferred stock," which is a hybrid between debt and equity. It has the tax deductibility of interest, like debt, and the option of deferring the dividends, like equity. Empire's financial statements classify the trust preferred stock as debt.

Staff should also note that the recommended ratemaking capital structure does not contain short-term debt. This is not because Empire does not issue short-term debt for purposes of funding its operations. Staff did not include Empire's short-term debt in the capital structure because as of December 31, 2009, Empire's Construction Work In Progress ("CWIP") balance exceeded its short-term debt balance. Because the financing costs capitalized in the Allowance for Funds Used During Construction ("AFUDC") account are based on the cost of short-term debt, this 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).

G. Cost of Common Equity

Staff estimated Empire'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 10). To this list Staff applied certain criteria in order to develop a proxy group comparable in risk to that of Empire. 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 Edison Electric Institute (EEI): This criterion eliminated thirty-one companies;
4. At least 70 percent of revenues from electric operations as classified 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 11.

2. *Constant-growth DCF*

In this case, Staff attempted to initially estimate the proxy group's cost of common equity using its traditional constant-growth DCF analysis, 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 five year 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 12-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 12-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 12-3 presents the averages of the growth rates shown in Schedules 12-1 and 12-2. 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 13). 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 3.88 percent to 11.70 percent and have a standard deviation of 2.28 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 5.92 percent (column 3 of Schedule 14) 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 (4.2 percent for 2015 through 2020). 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 January 2010 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 16 presents the average high/low stock price for each comparable for the period of November 1, 2009, through January 31, 2010.

Column 1 of Schedule 17 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 17 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 4.92 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 17, 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 8.92 percent to 9.92 percent.

Also shown on Schedule 17 is a Company-specific indicated cost of common equity of 12.88 percent. Because Staff just simply added an unsustainable EPS projected growth rate to Empire's dividend yield, this should not be misconstrued as Staff's estimate of Empire's cost of equity.

<u>2. *Multiple-Stage DCF*</u>

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 current Union Electric rate case, Case No. ER-2010-0036, and the last two rate cases filed by Great Plains Energy's subsidiaries, the 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 the Congressional Budget Office's and Energy Information Administration's 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 the time of 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 multi-stage 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 Empire. 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 EPS 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 *2010 The Budget and Economic Outlook*. If the growth rate resulting from a constant-growth DCF calculation is not expected to be constant and/or sustainable, then a multiple-stage DCF analysis is more 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 impacted by changes in the economy as other sectors. 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.[7,8]

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 a reasonable approach for mature industries that are simply going 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 rate (plus a factor for inflation). This should cause electric utility companies to settle on a perpetual growth rate slightly higher than three percent, which Staff will support later in this section of the 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

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

[8] 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.

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. 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 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 2017 through 2020.[9] Although this projected inflation rate does not extend past 2020, 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 treasury bonds and 20-year treasury inflation protected securities ("TIPS"). The yield on 20-year nominal treasury bonds averaged 4.50 percent in January 2010, whereas the yield on the 20-year TIPS bond averaged 2.00 percent in January 2010. This implies that in January 2010 investors required an inflation premium of 2.50 percent. The implied inflation premium was 2.41 percent in December 2009 and 2.34 percent in November 2009. If the inflation premiums for these three months are averaged, then this implies an approximate inflation premium of 2.42 percent. Considering all of this information, Staff decided a 3.35 percent growth rate is reasonable for purposes of its multi-stage DCF analysis.

A perpetual growth rate of 3.35 percent appears to be conservative compared to long-term expected growth in the electric utility industry even before the slow down in the

[9] "The Budget and Economic Outlook: Fiscal Years 2010 to 2020" January 2010, *Congressional Budget Office.*

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 3.35 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 provides its multi-stage DCF analysis recommendation on Schedule 19. Schedule 19 shows the proxy group's overall average cost of common equity and Staff's recommended range based on this average. Staff's initial findings using a multi-stage DCF analysis is an estimated of cost of common equity in the range of 8.55 percent to 9.55, with a midpoint of 9.05 percent. Because the average credit rating of the comparable companies is BBB+ and the credit rating of Empire is BBB-, Staff increased the lower end and the upper end of the range by 35 basis points to reflect the higher risk implied by this credit rating differential. The spreads between A-rated utility bonds and BBB-rated utility bonds has averaged approximately 50 basis points during the last quarter of 2009. However, spreads before the credit crisis occurred were closer to 30 basis points. At the height of the credit crisis, this spread reached unprecedented levels of approximately 160 basis points, which was clearly shown to be an anomaly. Although Staff is hopeful that the spreads between A-rated utility bonds and BBB-rated utility bonds will continue to narrow back to the spreads realized before the credit crisis, Staff decided it should base its adjustment on more recent spreads since additional risk aversion is still implied in recent spreads. This approximately equates into a 17 (50/3 = 16.67) basis point differential for each notch within the credit rating and because Empire's credit rating is two notches below the average credit rating of the comparable companies, Staff believes it is appropriate to adjust the proxy group cost of common equity estimate up by 35 basis points. Therefore, Staff recommends a return on common equity in the range of 8.90 percent to 9.90 percent based on the results of its comparable company multi-stage DCF analysis.

Although Staff also shows a multi-stage indicated cost of common equity for Empire on a stand-alone basis on Schedule 19, as with the constant-growth DCF, this estimated should not be misconstrued as a reliable estimate of Empire's cost of equity. This is shown for informational purposes only. However, this illustrates how assuming DPS will grow at the rate of a 5-year projected EPS growth rate can cause a higher than reasonable cost of common equity estimate for a single company.

Staff does not believe its multi-stage DCF analysis should be adjusted upward for quarterly compounding as the Commission suggested 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. Because this results in the assumption that investors will receive a higher amount of dividends than they should actually receive, this biases the estimated cost of equity upwards because it requires a higher discount rate to discount higher than expected cash flows. 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 5.92 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 9.40 percent, this would result in an average present value for these dividends of $61.99. 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 $64.35 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 11.08 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 believes this supports its opinion that electric utility stock values are supported by lower discount rates rather than higher expected growth in cash flow. Because Staff's calculation for estimating the cost of equity already has an upward bias, as explained above, Staff does not believe its multi-stage DCF analysis should be further adjusted upward for quarterly compounding.

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 model 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 used an average yield on 30-year T-bonds for its risk-free rate. In this case, the Staff decided to use an average monthly yield for the most recent three months (November and December 2009 and January 2010). 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 January 2010. 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 approximately 4.47 percent and this was obtained from the St. Louis Federal Reserve website. If Staff had continued to use the most recent monthly yield in this analysis, its CAPM cost of common equity estimate would have been 13 basis points higher.

For the second variable, beta, Staff used Value Line's betas for the comparable group of companies. Schedule 18 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.*[10]

Schedule 18 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 8.18 percent and 7.05 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, Empire. 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 Empire, 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

In order to further test the reasonableness of Staff's estimated cost of common equity for Empire'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

[10] The 2010 Yearbook is not yet available.

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 December 2009, Moody's "A" rated bonds and "Baa" rated bonds were yielding 5.79 percent to 6.26 percent respectively. If you add 3 percent risk premium to these yields, the indicated cost of common equity is 8.79 percent to 9.26 percent.

Although Staff sought to review equity research reports to test the reasonableness of its recommendation as Staff did in the current Union Electric rate case, Case No. ER-2010-0036, Empire's response to Staff Data Request No. 204 did not include any such published equity research reports. This may be due to the possibility that there were not reports published on Empire in the last couple of years or it is possible that Empire did not provide these reports in response to Staff's data request. Staff is seeking clarification from Empire on this issue in a follow up data request, Data Request No. 204.1.

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 of its analyses, Staff believes an fair cost of common equity estimate in this case is in the range of 8.90 percent to 9.90 percent, with a mid-point of 9.40 percent. Staff may adjust its recommended cost of common equity based on any changes in Empire'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 year 2009 was 10.5 percent based on 39 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; fourth quarter – 10.54 percent based on seventeen 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, Inc. 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 year 2009 was 8.23 percent based on thirty eight 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; fourth quarter – 8.30 percent based on eighteen 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 Empire 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 Empire'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.

Staff understands that the Commission will not automatically exclude a recommended ROE if it falls outside of the Commission's zone of reasonableness range, but to the extent that the Commission may believe that part of Staff's range falls outside this zone, Staff would recommend the Commission consider the part of the range that falls within this zone.

I. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.85 percent to 8.33 percent was developed for Empire (see Schedule 22). This rate was calculated by applying an embedded cost of long-term debt of 6.75 percent and a cost of common equity range of 8.90 percent to 9.90 percent to a capital structure consisting of 47.38 percent common equity, 48.79 percent long-term debt and 3.84 percent preferred stock. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that Empire be allowed to earn a return on its rate base in the range of 7.85 percent to 8.33 percent, with a midpoint recommendation of 8.09 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: Shana Atkinson

VI. Rate Base

A. Plant In Service and Depreciation Reserve

1. Plant in Service as of December 31, 2009

Accounting Schedule 3, Plant in Service, reflects the rate base value of Empire's plant in service at December 31, 2009, by account.

Staff Expert: Casey Westhues

2. Plant Adjustments; Allocations to Gas

The Staff has adjusted Empire's plant balances in Plant to allocate a portion of the Company's general plant to Empire's natural gas business. These adjustments are necessary as Empire records its general plant in service balances on its electric books in entirety.

Staff Expert: Casey Westhues

3. Plant Adjustments: Plum Point Unit Train

An adjustment was also made to remove the cost of the Plum Point Unit Train capitalized lease from plant in service as the Plum Point generating unit has not yet met the in-service criteria for inclusion in rate base.

Staff Expert: Casey Westhues

4. Depreciation Reserve as of December 31, 2009

Accounting Schedule 4, Depreciation Reserve, reflects the rate base value of Empire's depreciation reserve at December 31, 2009, by account.

Staff Expert: Casey Westhues

5. Reserve Adjustments: Allocation to Gas

Because Empire records its depreciation reserve associated with general plant on its electric books in entirety, it is necessary to allocate a portion of the general plant depreciation reserve to Empire's natural gas, telephone, and water business units for rate case purposes.

Staff Expert: Casey Westhues

6. Reserve & Depreciation Reserve Adjustments: Capitalized Incentive Compensation

During test year and update period, Empire capitalized a portion of its compensation for its Employee Stock Purchase Plan and its Bonus Incentive Plan ("Lightning Bolts"). Since the Staff recommended disallowance of these non-cash compensation expenses from its cost of service in the income statement (see Section VIII. F. 5. c.), the Staff is also making a recommendation to remove these costs from rate base in this case. The Staff made adjustments to the plant in service in the amount of ($220,229) and depreciation reserve in the amount of ($6,343) in order to eliminate these amounts from cost of service.

Staff Expert: Paul R. Harrison

B. Cash Working Capital (CWC)

Cash Working Capital ("CWC") is the amount of funding necessary for a utility to pay the day-to-day expenses incurred in providing utility services to its customers. When a utility expends funds in order to pay an expense necessary for the provision of service before its customers provide any corresponding payment, the utility's shareholders are the source of the funds. This shareholder funding represents a portion of each shareholders' total investment in the utility, for which the shareholders are compensated by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the CWC-related funding they have invested.

Customers supply CWC when they pay for electric services received before the utility pays expenses incurred in providing that service. Utility customers are compensated for the CWC they provide by a reduction to the utility's rate base. By removing these funds from rate base, the utility earns no return on that funding which was supplied by customers as CWC.

A positive CWC requirement indicates that, in the aggregate, the shareholders provided the CWC for the test year. This means that, on average, the utility paid the expenses incurred to provide the electric services to its customers before those customers had to pay the utility for the provision of these utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provided the CWC for the test year. This means that, on average, the customers paid for the utility's electric services before the utility paid the expenses that the utility incurred to provide those services.

The Staff performed a study of Empire's test year CWC lags, which indicated a positive CWC requirement. This means that in the aggregate Empire's shareholders have provided the CWC to the Company during the test year. The Staff recommends that the shareholders should be compensated for the CWC that they provide through an increase in the Company's rate base, in the total amount of $2,572,810.

The Staff's CWC calculation is as follows:

- **Account Description**: lists the types of cash expenses which Empire pays on a day-to-day basis.
- **Test Year Expenses**: Provides the amount of annualized expense included in Empire's cost of service. These expenses are based on the dollars associated with those items on an adjusted jurisdictional basis according to the account description.
- **Revenue Lag**: indicates the number of days between the midpoint of the provision of service by Empire and the payment by the ratepayer for such service. Further explanation of the Revenue Lag can be found later in this Report.
- **Expense Lag**: indicates the number of days between the receipt of and payment for the goods and services (i.e. cash expenditures) used to provide service to the ratepayer. Further explanation of the Expense Lag can be found later in this Report.
- **Net Lag**: results from the subtraction of the Expense Lag from the Revenue Lag

1) CWC Factor: expresses the CWC Lag in days as a fraction of the total days in the test year. This is accomplished by dividing the Net Lag by 365.

2) CWC Requirement: cash working capital requirement needed for each expense listed. The amounts in this area are calculated by multiplying the test year/annualized balances with the CWC Factor.

The result of the Staff's CWC analysis is reflected on Accounting Schedule 8, Cash Working Capital. The Staff's CWC analysis result is also included in the Rate Base Accounting Schedule 2 in the section entitled "Add to Net Plant In Service." Other aspects of the Staff's CWC analysis results are included in the Rate Base Schedule in the section entitled "Subtract From Net Plant" in the following line items: Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

1. Revenue Lag

The revenue lag is the amount of time between the day the Company provides the utility service, and the day it receives payment from the ratepayers for that service. The Staff's overall revenue lag in this case is the sum of three (3) subcomponents. They are as follows:

1) Usage Lag: The midpoint of average time elapsed from the beginning of the first day of a service period through the last day of that service period;

2) Billing Lag: The period of time between the last day of the service period and the day the bill for that service period is placed in the mail by the Company; and

3) Collection Lag: The period of time between the day the bill is placed in the mail by the Company and the day the Company receives payment from the ratepayer for the services provided.

The Staff's recommended revenue lag in this case is presented as follows, and the Staff's calculation for each component will then be explained:

	Staff
Usage Lag	15.21
Billing Lag	4.14
Collection Lag	27.46
Payment Lag	0
Total Revenue Lag	46.82

The usage lag was determined by dividing the number of days in a typical year (365) by the number of months in a year (12) to yield the average number of days in a month (30.42). The 30.42 was then divided by two (2) to yield an average usage lag of 15.21 days. This further calculation using two (2) as the divisor is necessary since the Company bills monthly and it is assumed that service is delivered to the customer evenly throughout the month.

The billing lag is the time it takes between when the Company reads the meter and when the bills are subsequently mailed to customers. In this case Empire's billing lag is a comparable number of days to what it has been in the past. The Staff accepted Empire's billing lag day calculation in its filed lead/lag study.

The collection lag is the time lapse between the point on average when a bill is mailed by Empire and when Empire receives the customer payment. The collection lag was calculated by using the "accounts receivable turnover" method. An accounts receivable turnover calculation is an estimation of the amount of time on average the Company's sales are due from customers (i.e., included in their Accounts Receivable) before the amounts owed are collected from customers. In this proceeding, the Staff calculated Empire's Accounts Receivable Turnover by starting with the monthly Missouri jurisdictional accounts receivable balances for the test year, and subtracting the portion of Empire's Missouri jurisdictional net write offs from the balances. The Staff made a conservative assumption that Empire's bad debts were included in the Company's accounts receivable balances for an average of 75 days before they are written off as bad debt. It is appropriate to deduct Empire's bad debt write-offs from its accounts receivables balances when performing a turnover calculation because the Company is allowed rate recovery of a reasonable level of bad debt expense elsewhere in the rate process. The Staff then calculated an average net accounts receivable balance for the test year. Empire's actual test year billed electric revenues were then divided by the average receivables calculation to determine the accounts receivable turnover ratio. The collection lag was then determined by dividing the number of days in a year (365) by the accounts receivable turnover ratio (13.29) to produce a collection lag of 27.46 days.

The sum of Staff's usage, billing, and collection lags for Empire in this proceeding is 46.82 days.

<u>2. Expense Lags</u>

Empire performed a lead/lag analysis for its major expenses as part of its filing in this case. The following expense lags calculated by Empire were examined for accuracy and the results were determined to be reasonable; therefore, the Staff accepts the Company's calculations for these items:

- Payroll Expense
- Federal Income Tax Withheld
- State Income Tax Withheld

- Employees 401K Withheld Employers 401K Matching
- Employers Life Insurance Matching
- Employers Healthcare
- Employers AD&D
- Employers Dental/Vision
- FICA Withheld
- Employer FICA
- Federal Unemployment
- State Unemployment
- Property Taxes
- Sales Taxes
- Interest
- Income Tax

Each of these expenses was calculated using the midpoint of the service period to the actual payment date to arrive at the expense lag.

For purposes of expense lag calculations, a "service period" is the period of time when a particular service is provided for a utility. For example, a service provided to a utility by an outside vendor over a 30-day period, and billed on a monthly basis, would create a "service period" of 30 days for that particular service. A calculation of an expense lag for that service would begin at the midpoint of that service period to reflect the assumption that the utility received the benefit of that service evenly over the 30-day period.

The Staff performed its own calculations of the Fuel - Coal, Fuel - Gas, Fuel - Oil, Purchased Power, and Cash Voucher lags. This is because Empire's calculations of these lags inappropriately assumed that no "service period" existed in relation to these expenses.

In order to determine accurate fuel expense lags, a service period of 30 days was assumed from each invoice date. A midpoint was then calculated for the service period. The midpoint was then subtracted from the actual payment dates to determine the expense lags for fuel. The Staff's fuel lag results were: Coal-39.12 days, Gas-27.09 days, and Oil-37.60 days.

Regarding the purchased power expense lag, the Staff received only one invoice relating to Empire's purchased power transactions during the test year, which was insufficient to calculate a purchase power lag. As a result, the Staff decided to use the purchased power lag calculated from the prior rate case, Case No. ER-2008-0093. The Staff has asked the Company for more updated information concerning its purchased power expense. Once this information is received the purchased power fuel lag may be modified, if appropriate.

The Cash Vouchers expense lag was calculated in the same manner as the fuel lags were. The Cash Vouchers line item in the Staff's CWC Study represents any cash expenses that aren't included in a separate line item on Staff Accounting Schedule 8, Cash Working Capital. For purposes of calculating the cash voucher lag, the Staff assumed a 30- day service period and used the actual payment date for the item to calculate the expense lag. The Cash Voucher expense lag was determined to be 40.74 days.

The Staff also performed its own calculations in this case for the pension lag, the vacation lag, the corporate franchise tax lag and the gross receipts tax lag.

For calculation of the pension expense lag, the Staff assumed that contributions to the Company's pension trust fund are made on a quarterly basis during each plan year, with a final contribution due in September of the following year.

For calculation of the vacation expense lag, the Staff assumed that Empire does not pay out vacation pay to eligible employees until a year has passed on average, after the employee has earned the right to take vacation. This position is consistent with that taken by the Staff in previous Empire rate cases.

In regard to the corporate franchise tax lag, the Staff measured this expense lag from the payment date for this annual tax due to the state and the midpoint of the year.

For gross receipts taxes, the Staff used the same expense lag it sponsored in Empire's last rate case, No. ER-2008-0093. The Staff has requested updated information regarding the timing of its payments of gross receipts taxes to cities/municipalities. If the Staff's calculation of the expense lag changes materially as a result of this information, the Staff will update its lead/lag study results later in this proceeding.

Empire is required to collect certain taxes for municipalities in which they operate. The gross receipts tax and the sales tax are included as separate line items on the ratepayer's bill. However, when the funds are received, Empire remits payments to the taxing authority based on the arrangement established with the taxing authority. Since Empire collects the taxes for the taxing authority and a corresponding service is not provided to the ratepayer by Empire, the Staff's measurement of the revenue and expense lags calculations start with the beginning point of the collection lag for these taxes. The collection lag was defined earlier in this report as the period of time between the day the bill is placed in the mail by Empire and the day Empire receives payment from the ratepayer for the services provided. As a result of using this methodology, the gross receipts tax and the sales tax CWC line items feature a shortened revenue lag compared to the other line items in the Staff's CWC Schedule.

The federal income tax offset, state income tax offset and interest expense offset do not directly appear in the Staff's Accounting Schedule 8, Cash Working Capital. These items appear as separate line items in the Staff's Accounting Schedule 2, Rate Base. These cash payments are known and certain obligations of Empire with payment periods and payment dates established by statute or bond indentures. The Staff believes amounts collected from ratepayers, which the Company intends to use for the payment of taxes and interest, represent a source of cash for Empire which has use of such funds until they are passed on to the appropriate taxing authority or bondholder. Therefore, the Staff believes it is appropriate to include taxes and interest as offsets in a lead/lag analysis.

The reason these items appear in the Staff's Accounting Schedule 2, Rate Base, rather than Accounting Schedule 8, Cash Working Capital is because the expense component used for these offsets is tied directly to the mechanical computation of the revenue requirement. The Staff's computer generated revenue requirement is based on a computer program with the capability of extracting appropriate amounts for federal income tax, state income tax, and interest expense based on amounts obtained from Accounting Schedule 11, Income Tax. The computer program applies the CWC factor for each respective component and places the CWC revenue requirement directly in Accounting Schedule 2.

Summary

In conclusion, the results of the study performed by Staff resulted in a positive CWC requirement. This means that in the aggregate the shareholders have provided the CWC to the

Company during the test year. Therefore, the shareholders should be compensated for the CWC that they provide through an increase to rate base.

Staff Expert: Casey Westhues

C. Prepayments, and Materials and Supplies

The Company has utilized shareholder funds to finance prepaid items such as insurance premiums and postage. The Company is later reimbursed by customers for these costs once the items are charged to expense during a subsequent period. The Staff has included these prepayments in rate base at the 13-month average level ending December 2009.

The Company also holds a variety of materials and supplies in inventory so the items can be readily available when needed in performing its utility operations. A 13-month average was taken of the materials and supplies (M&S) amounts in the Company's electric accounts. However, these accounts also include a certain amount of M&S inventory attributable to Empire's water operations. A 13-month average of the water inventory was taken and then subtracted from the 13-month average of total M&S to arrive at the amount of M&S to be included in rate base in this proceeding.

Staff Expert: Casey Westhues

D. Fuel Inventories

Coal Inventory - The Staff used the results of its fuel model to calculate the annual amount of coal used by each Empire generating plant to meet the Empire total company normalized native load. Empire of course operates in four retail jurisdictions, Missouri, Arkansas, Kansas and Oklahoma. "Native load" is the kilowatt or megawatt demand placed upon Empire's electric system by certain consumers of power, its regulated retail electric customers. To determine the amount of coal inventory, the average daily burn by unit must be calculated, which is derived by dividing the annualized tons burned by 365 days. Then, the average daily burn is multiplied by an appropriate number of days of inventory for each plant. The number of days of inventory of Powder River Basin (PRB), or "western" coal, for the Asbury 1 and 2 and Riverton 7 and 8 units is set at 60 days. This is the target number of days supply of coal Empire expects to maintain at its coal-burning plants. The PRB coal is currently supplied by three western coal suppliers: Arch Coal Sales, Peabody Coal Sales, and Cloud Peak Energy.

Empire also carries an inventory of local (Kansas) bituminous coal supplied by Phoenix Coal Sales and petroleum coke supplied by Oxbow Carbon and Mineral, both under contract; the days of inventory included for this coal and petroleum coke is also 60 days. The Staff has also used a 60-day calculation to establish Empire's rate base investment in the coal inventory maintained at Kansas City Power & Light Company's (KCPL) Iatan Generating Station, of which Empire is a 12% owner.

The Staff multiplied the total tonnage of inventory for each unit by the Staff's proposed delivered cost of coal per ton for that unit. This dollar amount was multiplied by the Staff's energy jurisdictional factor to arrive at the Missouri allocated amount with the result being the amount that is reflected as part of Fuel Inventories in Accounting Schedule 2, Rate Base.

Fuel Oil Inventory - The Staff used the 13-month average inventory quantities and a weighted average price for oil inventory levels.

Staff Expert: Keith D. Foster

E. Gas Stored Underground

Staff reviewed Empire's General Ledger account for Natural Gas in Storage (Account 151547) and found no activity during either the test year or update period. Staff concluded Empire did not maintain an inventory of stored gas to help meet its gas needs at peak periods during these periods. Therefore, Staff set the value of this rate base item at zero.

Staff Expert: Keith D. Foster

F. Prepaid Pension Asset / FAS 87 Regulatory Asset Tracker / FAS 106 Regulatory Asset Tracker

See the discussion of these items in Section VIII. F. 1. - FAS 87/Pension Expense and Section VIII. F. 2. - FAS 106/OPEBs Expense.

Staff Expert: Paul R. Harrison

G. Customer Demand Programs Regulatory Asset

Empire is currently part of the Customer Programs Collaborative (CPC) that was created as a result of the Stipulation and Agreement in Case No. EO-2005-0263, Empire's Experimental Regulatory Plan case. As a result of the Stipulation and Agreement in Case No. EO-2005-0263, the CPC retained a consultant to evaluate Demand Side Management (DSM) and affordability programs for Empire's Missouri customers. All unamortized actual costs associated with the CPC and new Demand Side Management programs are to be included in rate base as a regulatory asset, per the Stipulation And Agreement in Case No. EO-2005-0263. The Staff is using the year-end 2009 balance of this regulatory asset in rate base in this case. The Staff has also included an adjustment in the Income Statement to amortize these costs to expense (*see* Section VIII. L. 16. a.).

Staff Expert: Paul R. Harrison

H. Amortization of Electric Plant

The Staff has adjusted the amortization reserve for electric plant to reflect the updated balances through December 31, 2009. The amortization reserve balance as of December 31, 2009 is $7,566,173 and was included as an offset to rate base in the Staff's Accounting Schedules.

Staff Expert: Paul R. Harrison

I. Customer Deposits

The amount of customer deposits shown on Accounting Schedule 2, Rate Base, represents a 13-month average (December 2008 – December 2009) of Empire's customer deposits. Customer deposits are funds received from customers as security against potential loss arising from failure to pay for utility service. Since the deposits are interest-free loans to the company, the Staff included a representative level of $8,744,906 as an offset to rate base.

Interest on customer deposits is also in the Company's rates because customers should receive a reasonable rate of return on their deposits until the monies are refunded to them. The appropriate amount of interest to include in the Company's expenses can be determined by review of the applicable sections of Empire's Tariffs. The Tariff (Section 3 Pg. 8) states that "interest rate paid upon return of a deposit, per annum, compounded annually shall be equal to the prime rate published in the Wall Street Journal as being in effect on the last business day of December of the prior year plus 1%." The prime rate in effect as of December 31, 2009 was 3.25%. One percent was added to this rate for a total 4.25% interest rate on customer deposits. The amount of interest on customer deposits, $371,659, is included in Staff Accounting Schedule 10 as adjustment E.-138.1.

Staff Expert: Casey Westhues

J. Customer Advances

Customer advances are funds provided to Empire by individual customers of the Company to assist in the costs of the provision of electric service to them under certain circumstances. These funds are 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 this money, unlike customer deposits. The 13-month average of the customer advances account balances as of December 31, 2009, the end of the Staff's update period, is shown on Accounting Schedule 2, Rate Base.

Staff Expert: Casey Westhues

K. Deferred Income Taxes

Empire's deferred tax reserve represents, in effect, a prepayment of income taxes by customers prior to payment by Empire. For example, because Empire is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes paid by Empire 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 Empire. Therefore, Empire'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. Generally, deferred income taxes associated with all book-tax timing differences that are created through the ratemaking process should be reflected in rate base. The Staff has taken this approach in calculating the deferred income tax rate base offset amount in this case.

The deferred tax impact of the following past tax timing differences were included in the Staff's rate base offset: Accelerated Depreciation, Loss on Hedge Transactions, Gain on Hedge Transactions, License Software Amortization, Loss on Reacquired Debt, Ice Storm Expenses, Contributions in Aid of Construction, Post-retirement Benefits – Pensions, and Capitalized Interest.

Staff Expert: Paul R. Harrison

L. Commission Rules Tracker

During Empire's most previous rate case, Case No. ER-2008-0093, the Commission authorized Empire to set up a two-way tracker to account for any difference between Empire's incurred vegetation management (tree trimming) / infrastructure inspection costs compared to an estimated target annual amount of $8,575,000 (Missouri Jurisdictional) for these costs included in rates in that proceeding. The Report and Order stated on pages 72-73:

> The Commission will require Empire to implement a two-way tracker for measuring costs relating to infrastructure inspection and vegetation management. The tracker shall create a regulatory liability in any year where Empire spends less than the target amount, and a regulatory asset where the company spends more than the target amount. The assets and liabilities shall then be netted against each other and considered in Empire's next rate case. The annual target amount shall be set at $8.575 million, and Empire shall be allowed to recover that amount in its current rates.

The Commission's Rules concerning Electric Utility System Reliability Monitoring and Reporting Submission Requirements (4 CSR 240-23.010) and Electrical Corporation Infrastructure Standards (4 CSR 240-23.020) became effective in July and June of 2008, respectively, and Empire started booking vegetation management / infrastructure inspection costs for the purpose of this tracker during the month of August 2008 on an ongoing basis. As of December 31, 2009, Empire's two-way tracker balance was $1,635,396.

The Staff removed $611,234 related to minor maintenance and repair costs from the tracker balance (and made an adjustment to include this cost in adjusted Transmission and Distribution maintenance expense). The Staff removed repair costs from the tracker balance to be consistent with the Report and Order in Case No. ER-2008-0318, AmerenUE. At page 43 of that Order, the Commission addressed this issue as follows:

> . . . Staff would limit AmerenUE's recovery under these provisions to the amount spent for inspections, but would eliminate expenditures for repairs made as a result of those inspections. The Commission finds that AmerenUE's rates already allow for recovery of the expenditures required to repair its electric system. The fact those repairs may occur following an inspection does not mean the repairs would not eventually have been made anyway and there is no reason to believe the repairs would be more costly simply because they were made after an inspection. Thus, to allow recovery under this provision as an increased cost of complying with the rule could result in a double recovery of those costs.
>
> AmerenUE's witness . . . offered vague assurances AmerenUE would be able to separate repair costs resulting from inspections from repair costs resulting from a system failure or a customer report of problems, thus avoiding the double counting problem. However, the Commission is not convinced, and finds that the risk of double recovery precludes AmerenUE's attempt to recover repair costs under this provision. . . .[Footnotes omitted].

With this adjustment, the Staff's valuation of the Commission Rules tracker amount as of December 31, 2009 is $1,024,163, and the Staff has included this amount in its rate base. There is also an adjustment in the Income Statement to amortize the Commission Rules Tracker balance to expense over a five year period (*see* Section VIII. J. 5.).

Staff Expert: Paul R. Harrison

M. Carrying Costs Iatan 1 - Rate Base

The Company has deferred its carrying costs (monthly depreciation and AFUDC interest rates) associated with the Iatan 1 AQCS investment into Account 182.308, Iatan Deferred Carrying Costs. Empire was allowed to accrue and defer carrying costs on its Iatan 1 AQCS investment per the terms of Empire's Regulatory Plan, approved by the Commission in Case No. EO-2005-0263. The Staff included in its rate base the balance of this deferred asset as of December 31, 2009, in the amount of $2,720,536.

Staff Expert Paul R. Harrison

N. Regulatory Plan Additional Amortization - Rate Base

A Stipulation and Agreement titled, "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" was filed in Empire's 2006 rate proceeding, Case No. ER-2006-0315. Paragraph 5 provides for a rate base offset consisting of the accumulated balance of the Regulatory Plan Additional Amortization collected in rates:

> Further, Empire acknowledges that this Agreement is a resolution and is an implementation of the resolution of the gross-up issue that was intentionally left unresolved by the Regulatory Plan Stipulation And Agreement in Case No. EO-2005-0329. This resolution is implemented pursuant to and in compliance with the provisions of that Stipulation And Agreement, and that as a result thereof, any Regulatory Plan additional amortization that is provided to Empire pursuant to that Stipulation And Agreement shall be used as reduction to rate base for the longer of (a) at least ten (10) years following the effective date of the July 28, 2005 Report And Order in Case No. EO-2005-0329 or (b) until the investment in the plant in service accounts to which the Regulatory Plan amortizations are ultimately assigned by the Commission is retired. Such reduction to rate base is understood and accepted by Empire without reservation.

The revenue requirement approved by the Commission's Report and Order in Case No. ER-2006-0315 included a Regulatory Plan Amortization in the amount of $10,469,228. In Case No. ER-2008-0093, the Regulatory Plan Amortization amount was adjusted downward to an annual level of $4,463,535. The Staff has reflected a rate base offset of $22,836,352 representing the total amount of the Regulatory Plan Additional Amortization collected in rates as of the end of the update period, December 31, 2009, for this case.

Staff Expert: Mark L. Oligschlaeger

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 three jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale Operations. The particular allocation factor applied is dependent upon the types of costs to be allocated.

Staff, as did Empire, utilized a Twelve Coincident Peak (12 CP) methodology to determine demand allocation factors for Empire. Staff has calculated the following demand allocation factors for the twelve month period ending June 2009:

Retail Operations:	
Missouri	.8332
Non - Missouri	.1096
Wholesale Operations:	.0572

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 anticipated growth, annualizations and non-normal weather. Staff witnesses Paul R. Harrison and Curt Wells provided the growth and annualization adjustments. Staff witness Walt Cecil provided the weather adjustments. Staff has calculated the following energy allocation factors for the particular jurisdictions, utilizing the twelve month period ending June 2009:

Retail Operations:	
Missouri	.8271
Non - Missouri	.1070
Wholesale Operations:	.0659

Staff witness Bax provided these jurisdictional allocation factors to Staff witness Paul R. Harrison.

Staff Expert: Alan Bax

B. Corporate Allocations

As discussed earlier in this report, Empire is engaged in both regulated and non-regulated business operations. In the Staff's audit in this case, the Staff reviewed Empire's methods for assigning and allocating costs to its regulated electric, gas, and water operations, as well as to its other various non-regulated operations. Under Empire's corporate cost allocation system, costs are either directly assigned by Empire to business units (Empire refers to this assignment as "direct billing"), indirectly allocated to the business units, or allocated through use of a general factor.

Under the direct assignment approach, certain costs are directly assigned by Empire to its regulated electric operations by use of either vendor invoices or by labor charges. In the case of assignment by vendor invoice, each vendor invoice that includes charges for either goods and services that are a direct benefit to a specific business unit are directly assigned to the appropriate corresponding business unit. In the case of assignment by labor, employees are required to record their time electronically and to allocate such time based on the time each employee spends each month working on or for each business unit. Then, the system appropriately allocates a portion of that employee's salary to the appropriate business unit. The portion allocated to each business unit includes not only salary but also associated payroll taxes and fringe benefits.

Empire's indirect allocation factor is based upon a "unit of service method," which is employed by the Company in the event that incurred costs cannot be directly billed to the individual business units as described above. Empire uses the unit service method based on certain unit drivers. Examples of Empire's unit drivers are as follows: number of vouchers, number of active customers, number of purchase orders and number of personal computers. An allocation rate is then calculated based on information obtained from various general ledger entries and adjusted periodically.

For costs that cannot be direct assigned or that have no unit drivers, a "Modified Massachusetts" formula is used. A "Massachusetts formula" is a general allocation factor based upon three (3) separate measurements of directly assigned costs, and which is used to allocate a company's common costs that cannot be reasonably directly assigned or indirectly allocated to a company's business units. The "Modified Massachusetts" formula used by Empire consists of the averages of (1) profit margin, (2) payroll and net property, and (3) plant and equipment.

The Staff has reviewed Empire's methods for allocating costs among its different business units, and believes they are reasonable. The Staff's case reflects the most current allocation percentages used by Empire.

Staff Expert: Paul R. Harrison

VIII. Income Statement

A. Rate Revenues

1. Introduction

Since the largest component of operating revenues result from rates charged to Empire'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 that Empire charges to 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). 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: Paul R. Harrison

2. Definitions

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

Rate Revenue: Test year rate revenues consist solely of the revenues derived from Empire's charges for providing electric service to its Missouri retail customers (native load). Empire'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). Fuel Adjustment Clause (FAC) revenues are not included in rate revenues.

Margin from Off-System Sales: Margin from off-system sales is the profits that Empire makes conducting sales of electricity to other utilities at non-regulated prices. The profit margin is calculated as the gross revenues from the sale less the expenses Empire incurs. In the past, such margins have been used to reduce base rates for customers in general rate proceedings. The Staff is now recommending that Empire's off-system sale revenues and expenses be eliminated from consideration in general rate proceedings, and instead be handled entirely through Empire's Fuel Adjustment Clause mechanism.

Other Operating Revenue: Other operating revenue includes Forfeited Discounts, Reconnect Charges, Rent from Electric Property, Miscellaneous Electric Revenues, SO2 Allowances and Renewable Energy Credits (REC).

Staff Expert: Paul R. Harrison

3. The Development of Rate Revenue in this Case

The objective of this section is to determine annualized, normalized test year sales and revenues by rate classes. This section also includes a discussion of the annualization of Excess Facilities Charges.

The intent of the Staff's adjustments to test year Missouri sales and rate revenues is to determine the level of revenue that the Company would have collected on an annual, normal-weather basis, based on information "known and measurable" at the end of the update period.

The two major categories of revenue adjustments are known as "normalization" and "annualization". Normalizations deal with test year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect; for example, test year weather. Annualizations are adjustments that re-state test year results as if conditions known at the end of the update period had existed throughout the entire test year.

Staff Expert: Paul R. Harrison

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Development of Weather Normalization Factors

Electric usage typically varies as the outside temperature changes due to loads for heating or cooling. Air conditioning and electric space heating are both prevalent in Empire's service territory; therefore, Empire's electric load is correlated with and responsive to changes in temperature.

As observed temperatures during the test year deviated from normal temperatures, a weather impact analysis was required to adjust actual consumption of electricity to that which would have been consumed under normal conditions by weather sensitive customer classes. Electricity consumption for the following classes was weather normalized: Residential (RG); Commercial (CB); Small Heating (SH); Total Electric Building (TEB); and General Power (GP). The Large Power Services class customer loads were annualized individually rather than weather normalized as a class due to that class' relative insensitivity to changes in temperature. Please see Staff witness Manisha Lakhanpal's discussion of annualizations in subsection h for additional information on this topic.

The weather sensitive class' weather response functions were modeled by class using two-day weighted mean temperatures and the mean of the hourly load research sample by means of multivariate regression analysis and the MetrixND® software package on a calendar month basis. The resulting weather response functions were then simulated using normal temperatures to produce normalized weather usage on a calendar month basis. Staff witness Manisha Lakhanpal provided the actual and normal two-day weighted mean daily temperatures that were used in the analysis.

Billed usage data, provided by Empire in response to Staff Data Request No. 133, was analyzed to find billing corrections such as incorrect original bills, subsequent cancellation/corrections and correct re-bills. Known and discovered incorrect bills and billing corrections were eliminated from the data and incorrectly booked re-bills were booked to the correct months. Based on these adjustments, Staff was able to determine actual usage on a revenue month basis.

Staff witness Curt Wells of the Energy Department used each class' monthly weather normalization usage adjustment factors to calculate the overall weather normalization usage and revenue adjustment.

Staff witness Manisha Lakhanpal provided the actual and normal two-day weighted mean daily temperatures that were used in the analysis.

Staff Expert: Walt Cecil

b. Weather Normal Variables

The actual weather experienced during the test year is unique and unlikely to be repeated exactly in each of the years when the new rates from this case are in effect. Since each year's weather is unique, test-year usage need to be adjusted to "normal" weather. In this case Staff's adjustments to Usage and Revenue are based on a test year period (July 08- June 09).

Staff selected Springfield, MO weather station to develop "normal" average temperatures with which to compare the test year temperature. The time period used in determining the normal values of weather variables is the 30-year period (January 1, 1971- December 30, 2000) as used by NOAA[11]. NOAA, states that "climate normal is defined, by convention, as the arithmetic mean of a Climatologically element computed over three consecutive decades." However, NOAA's adjustments are applied to monthly temperatures over the period, and as a result they do not contain daily variation in temperature for weather-normalizing electricity use. The weather normalization process requires daily temperature normals, because electricity usage varies differently at extreme daily temperatures than it does at mild daily temperatures. Consequently, Staff adjusted daily data to correspond with the NOAA monthly average.

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

For this case Staff followed the methodology used by Staff in the Company's most recent rate case (Case No. ER-2008-0093) to calculate the daily normal weather temperature used to normalize both class usage and hourly net system loads. This ranking method estimates daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating normal extremes. The daily temperature normals are calculated by averaging the ranked temperatures in each year of the 30-year normals period, irrespective of the calendar date. This results in the normal extreme being the average of the most extreme temperatures in each year of the normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

[11] National Oceanic and Atmospheric Administration

Because actual temperatures do not smoothly move up and down during the year[12], these normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test year.

This information was provided to Staff witness Walt Cecil for use in weather normalization of usage and Net System Input.

Staff Expert: Manisha Lakhanpal

c. Weather Normalization of Usage and Revenue

Usage and revenue were normalized for the Residential (RG), Commercial (CB), Small Heating (SH), Total Electric Building (TEB), and General Power (GP) rate classes, after billing adjustments were applied.

For the RG, CB, and SH rate schedules, Staff applied a regression to model the relationship between average use per customer and the percentage of test year usage that are priced in the first rate block. This relationship was then applied to the monthly use per customer before and after the weather adjustment, using the normalization factors that Staff witness Walt Cecil had provided. This computation resulted in normalized usage by rate block, which were then converted to total normalized revenues by multiplying rate block usage by the appropriate rates.

For the GP and TEB rate schedules, the weather adjustment to rate revenues was calculated by an average realization methodology, excluding customer and demand charges. This methodology assumes that the weather adjustment to usage in each month is distributed into the rate blocks in proportion to the distribution of actual test year usage. Another interpretation of this average realization methodology is that any additional usage due to weather normalization should be priced at the same average price as all other usage in that month.

The GP class billing units and revenues were further subdivided by voltage with separate weather adjustments applied to each voltage level.

Staff Expert: Curt Wells

[12] 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.

d. Annualization for Rate Change

Test year rate revenues do not fully reflect the rate changes implemented on August 23, 2008, as a result of Case No. ER-2008-0093. Thus test year revenues are understated by the difference between the amount that was actually billed to customers and the revenue that would have been realized by the Company if the current rates had been in effect throughout the entire test year. Staff's method of computing annualized revenues for each rate class was to multiply test year billing units by current rates. The difference between these revenues and those billed during the test year under the prior rates provided the amount of the adjustment for the rate change.

Staff Expert: Large Power and Praxair: Manisha Lakhanpal

Staff Expert All other classes: Curt Wells

e. 365-Days Adjustment to Revenues

Calendar months and revenue months differ from one another because the time periods they cover begin and end differently. Calendar months coincide with the calendar, beginning on the first day of the month and ending on the last day of the month. Revenue months are an aggregation of bill cycles and begin on the first day of the first billing cycle and end on the last day of the last billing cycle. This aggregation of bill cycles may or may not coincide with a 365 day calendar year. In order to account for this difference, a "days" adjustment to convert the annual weather normalized revenue month usage to equate with the annual weather normalized calendar month usage was calculated. This annual adjustment was provided to Staff witness Curt Wells who allocated the adjustment to the test year months in proportion to the actual usage occurring in each month and then applied appropriate rates to determine the revenue adjustment.

For Large Power and Special Transmission Service Contract rate classes, rate revenue and usage is measured by billing month (the period of time over which the staggered bill cycles result in each customer being billed precisely once) rather than by calendar month. The difference between total usage days during the test year and 365 days gives us the days adjustment.

Staff Expert: Large Power MO and Non MO usage: Manisha Lakhanpal

Staff Expert for all other classes: Walt Cecil

f. Removal of Gross Receipts Taxes and Unbilled Revenue

The Staff made several additional adjustments to the Company's per book revenues. Adjustments were made to each revenue category to remove the test year city franchise taxes from the operating revenues.

Gross receipts taxes (also known as city franchise taxes) are not operating revenues. The Company acts merely as a collecting agent and remits the taxes to the appropriate taxing entities. City franchise taxes are reported as both a revenue and expense item on the Company's books. Therefore, both revenue and expense adjustments are necessary to eliminate this item.

The Staff made adjustments to eliminate unbilled revenues from the test year. The unbilled revenue adjustment reflects the Company's test year revenues on a billed basis. In the test year, there are electric sales to customers relating to either usage periods outside the test year, as well as electric usage that has not yet been recognized on issued bills. To recognize this usage for financial reporting purposes, utilities generally book an estimate of unbilled revenue on its books. The purpose of the Staff's unbilled adjustment is to remove any estimated revenues from the test year of the company's actual monthly revenues. For purposes of a rate case, the Staff's adjusted level of revenues should be based upon actual billed revenues only.

Staff Expert: Paul R. Harrison

g. Customer Growth (Annualization)

The Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of the update period (December 31, 2009) had existed throughout the entire test year. Customer growth was calculated for the Residential, Commercial, Small Heating, Total Electric Building, and General Power customer classes.

The only retail customer rate class for which this approach is not taken is the Large Power group. The process used for the Large Power group is described in subsection h. The Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, Commercial, Small Heating, Total Electric Building, and General Power in order to provide the annualized level of sales and revenues at December 31, 2009.

Staff Expert: Paul R. Harrison

h. Large Power Customers, Praxair and Non-Missouri Large Power Customer Annualizations

The objective of this section is to determine annualized, normalized test year usage and revenues for the rate classes determined not to be weather sensitive, i.e., the Missouri Large Power (MO LP) Customers , Praxair, and Non-Missouri Large Power (Non-MO LP) Customers.

The adjustments are for the test year of July 1, 2008 – June 30, 2009. There were 38 customers in the Company's MO LP rate class and 12 Large Power customers in its Non-MO LP class during the test year. A data check was done for billing corrections prior to doing adjustments. LP customers were then annualized on an individual customer (account) basis. Their individual monthly demand and energy use, measured over multiple years prior to the test year, the 12 months of the test year, were examined graphically to determine the adjustment needed.

The general intent of an annualization is to re-state test year usage results as if a known condition had existed throughout the entire test year. 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 due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers.

Out of the 38 MO LP customers, only one LP customers' load was adjusted by replacing the non-representative monthly usage with a more representative historical load.

At the beginning of the test year there were 12 Non-MO LP accounts. During the test year two of those accounts were absorbed by two other Non-MO LP accounts. The usage of these two customers was annualized for a twelve month period.

After reviewing the test year data for Praxair, Staff determined that no annualization adjustment was required.

Staff Expert: Manisha Lakhanpal

i. Special Contract Revenue Imputation

The special treatment of the interruptible credits associated with Praxair's contract stipulated in Case No. ER-2001-299 was considered effective through October 2010, but revenues were imputed as if the contract did not exist to prevent harm to other ratepayers.

Staff Expert: Manisha Lakhanpal

j. Non-Missouri Adjustments

Usage for the Residential, Commercial, Small Heating, Total Electric Building, and General Power classes for non-Missouri customers were adjusted for weather and "days" and were provided to the Staff auditors for their growth calculation. The adjusted usage, along with the usage of all other non-Missouri rate classes, was provided to Staff witness Walt Cecil for use in developing Net System Input.

Staff Expert: Curt Wells

k. Rate Switching

During this particular test year and update period, 82 customers changed rate classes. Fifty moved between the CB and GP classes, 13 moved between SH and TEB , one moved from CB to SH, 15 moved from CB to TEB, and three moved from SH to GP, Billing information indicated that this rate switching was likely due to a combination of load changes and economic reasons (i.e., to lower the customer's bill). While the overall effect of rate switching on usage nets to zero (one class' increase exactly equals the other class' decrease), the effect of this rate switching was to reduce Empire's overall rate revenues.

Those customers who switched into and out of each of these classes were handled separately. The billing units and revenue of these customers were removed from their original rate code. Their total billing units for the test year were then re-priced based on their final rate code and their revenues were added to the final rate code.

Staff Expert: Curt Wells

l. Annualization of Excess Facility Charge Revenues

These revenues result from charges to customers for facilities provided in excess of the facilities normally made available to similarly sized customers. These revenues are annualized for changes during the test year in the facilities provided to determine the revenue that would have been earned had these facilities been in use the entire test year.

Staff Expert: Curt Wells

m. Results

The results of test year adjustments to the classes' rate revenue can be found in the RateRevSummary tab of the Staff's Accounting Schedules.

Staff Expert: Curt Wells

B. Off-System Sales and Transmission Revenue

1. Off-System Sales (OSS)

As previously discussed, the Staff is proposing to eliminate Empire's revenues and expenses associated with its Off-System Sales (OSS) from the case, in order to handle this item through Empire's Fuel Adjustment Clause (FAC) mechanism. Therefore the Staff has adjusted Empire's level of test year OSS revenues to zero in Adjustment Rev-3.1 in Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert: Keith D. Foster

2. Transmission Revenue

The Staff is recommending a level of transmission transaction margins (revenues less related expenses) be reflected in Empire's cost of service based upon a three-year average of the transactions from calendar years 2007 through 2009. The test year and update period margins from transmission transactions were negative for Empire, which means that Empire paid more to other transmission-owning utilities for transmission service than Empire received from other utilities for transmission service. The Staff believes use of a three-year average in this case produces a more normal level of transmission margin. The Staff adjustment Rev-3.2 increases test year transmission transaction margins to a total of $348,761.

Staff Expert: Keith D. Foster

C. Miscellaneous Revenues

1. SO2 Allowances

On January 18, 2005 the Commission approved the Unanimous Stipulation and Agreement relating to EDE's "SO2 Allowance Management Policy (SAMP)" in Case No. EO-2005-0020 (2005 Agreement). In this document, the parties agreed that Empire should be allowed to manage its sulfur dioxide emissions allowance inventory according to the "SAMP" as detailed in the 2005 Agreement. In accordance with the 2005 Agreement and past ratemaking practice, the Staff is proposing an adjustment to Other Operating Income in the amount of $157,899. This adjustment reflects above-the-line inclusion in revenues of the gain on the sale of SO2 allowances by Empire for the twelve months ended December 31, 2009.

SO2 allowances are currently reflected in Empire's Fuel Adjustment Clause calculations and the Staff recommends that this treatment continue.

Staff Expert: Paul R. Harrison

2. Renewable Energy Credits (REC)

In 2009, Empire began receiving wind energy from Cloud County Wind Farm, LLC pursuant to a contract. In addition, Empire began receiving wind energy from Elk River Windfarm. Empire is currently receiving wind energy from both of these entities to meet its customers' energy demand. As a result of these contracts, Empire receives Renewable Energy Credits or Certificates (RECs), which are credits issued under the Center for Resource Solutions' "green-e" program to certify that one megawatt-hour of electricity has been generated by a facility engaged in the production of renewable energy, such as wind, solar or biomass. RECs are tradable and can be bought and sold.

During the test year, Empire booked $1,165,658 (Missouri Jurisdictional) of proceeds from sale of RECs into Account 456.073, Miscellaneous. Electric Rev-Green Credits. The Staff made an adjustment of $200,888 to the miscellaneous revenue account to increase REC revenue to the level realized during the twelve months ending December 31, 2009, the end of the Staff's test year update period. The Staff believes that this approach is consistent with the method that was used to normalize and/or annualize the other revenue in this case. Staff recommends that the REC's be included in the FAC calculations.

RECs are not currently reflected in Empire's Fuel Adjustment Clause. The Staff recommends that RECs be included in the Fuel Adjustment Clause mechanism on an ongoing basis in this case.

Staff Expert: Paul R. Harrison

3. Water Revenues

There are amounts recorded by Empire in the test year as electric revenues that relate to forfeited discounts and returned check fees for Empire's water business. The Staff has eliminated these revenues from the revenue requirement in this case.

Staff Expert: Paul R. Harrison

4. Other Revenues

Empire's "other" revenues include forfeited discounts and rents from property. The Staff reviewed Empire's totals of other revenue over the last five years. Based upon this review, the Staff believes Empire's test year level of booked other revenues is representative of an ongoing, annualized level of revenue for each respective category of costs and, therefore, does not require an adjustment.

Staff Expert: Paul R. Harrison

D. Fuel and Purchased Power

The Staff's adjustments to annualize and normalize Empire's fuel expense are reflected in Staff's Exhibit Modeling System Accounting Schedule 10, Adjustments to Income Statement. In addition to these adjustments, the Staff is making adjustment to eliminate from test year expense the expenses associated with off-system sales.

Staff Expert: Keith D. Foster

1. Fixed Costs

Fuel and purchased power costs that do not vary directly with fuel burned are not included in the Staff's fuel model, because those costs were determined separately. The non-variable fuel costs that are included in fuel expense are typically referred to as fuel adders, described in the section below. The non-variable purchased power costs are referred to as capacity charges and these costs are annualized separately from purchased power energy costs.

Staff Expert: Keith D. Foster

a. Fuel Adders

The costs of fuel adders are determined separately from fuel model costs and are added to the level of fuel expense calculated by the model to determine overall fuel expense. The fuel adders in this case are natural gas transportation costs, storage charges, and trucking charges. All PRB coal destined to the Riverton units is delivered by rail to Asbury, and then hauled by Asbell Trucking to the Riverton plant. The Staff annualized the natural gas transportation expense based on Empire's contractual obligations with Southern Star on January 1, 2010; an 18-month average (July 1, 2008 to December 31, 2009) trucking charge of $3.6268 per ton was added to overall coal costs for the Riverton 7 and 8 units only for the cost of trucking PRB coal from the Asbury plant to the Riverton plant.

Staff Expert: Keith D. Foster

b. Purchased Power – Capacity Charges

Capacity charges represent fixed amounts Empire paid to the entity that reserves the MW capacity for Empire. Empire contracts for this power with various entities and pays a fixed component and an energy component. Generally, there is also an amount for operation and maintenance costs charged for the use of energy. The fixed component is paid as a "demand charge," generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

The Staff did not adjust Empire's test year level of purchased power capacity charges, as that amount remained the Company's ongoing level of expense for this item through the end of the update period.

Staff Expert: Keith D. Foster

2. Variable Costs

The Staff estimates the variable fuel and purchased power expense for Empire for the twelve months ending June 30, 2009, to be $144,882,730.

The Staff used the Real Time™ production cost model to perform an hour-by-hour chronological simulation of a utility's generation and power purchases. The Staff uses this model to determine annual variable cost of fuel and net purchased power energy costs and fuel consumption necessary to economically meet a utility's load within the operating constraints of the utility's resources used to meet that load. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense.

The model operates in a chronological fashion, meeting each hour's energy demand before moving to the next hour. It will schedule 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 and firm purchased power contract requirements. This model closely simulates the way a utility should dispatch its generating units and purchase power to meet the net system load in a least cost manner.

Inputs calculated by the Staff are: fuel prices, firm purchased power contract specifications, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. The Staff relied on Empire responses to data requests, and data Empire supplied to comply with 4 CSR 240-3.190, for factors relating to each generating unit such as: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Information from Empire's firm wholesale loads and firm purchased power contracts such as hourly energy available and prices are also inputs to the model.

Staff Expert: Shawn E. Lange

a. Fuel Prices

The Staff computed its level of fuel expense using prices and quantities contracted by Empire through the end of the test year update period, including prices and quantities agreed to in fuel and freight contracts that became effective as of January 1, 2010. These fuel prices included prices for coal, natural gas, and oil, as well as associated transportation charges.

Staff Expert: Keith D. Foster

i. Coal Prices

The Staff determined its coal price by generation facility based on a review and analysis of Empire's current coal purchase and coal transportation contracts. The Staff's proposed coal prices reflect Empire's actual contracted coal purchase and transportation prices in effect at January 1, 2010.

Staff Expert: Keith D. Foster

ii. Natural Gas Prices

The natural gas price used in this case by the Staff of $6.01 per MMBtu is composed of two components: hedged and non-hedged (spot) prices. The non-hedged component of natural gas prices was calculated using a twelve-month weighted average of Empire's actual commodity cost of natural gas purchased on the spot market during calendar year 2009, the end of the update period. The weighted average price for the non-hedged component in 2009 is $4.742 per MMBtu. The hedged component of natural gas costs was calculated by applying a weighted average for the actual hedged purchases contracted for at year-end 2009 that are applicable to Empire's forecasted gas needs for calendar year 2010. The weighted average price for the hedged component in 2010 is $6.309 per MMBtu. The Staff weighted the hedged gas price at 81% of its overall gas price recommendation, as Empire has contracted to meet 81% of its projected natural gas usage in 2010 with hedged gas supplies.

Empire's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert: Keith D. Foster

iii. Fuel Oil Prices

The Staff used a weighted average price of 1,269.65 cents per MMBtu to determine the fuel oil cost input in the fuel model in this case. This weighted average price was calculated by (1) converting each month's number of barrels purchased over a 13-month period into gallons; (2) dividing a total month's purchase in gallons by that month's total purchase costs to derive an average monthly price per gallon; (3) summing the totals for the 13-month period to calculate a weighted 13-month average cost per gallon which, in this case, is $1.769898; and (4) converting this per gallon price into the cents per MMBtu, 1,269.65. Empire burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite storage at its various facilities in sufficient capacity that only occasional purchases are necessary. As a result, Empire does not contract for or hedge oil costs. The Staff contends that using this weighting methodology properly prices out the oil held in storage purchased at lower than current market levels.

Staff Expert: Keith D. Foster

3. Spot Market Availability and Prices

Spot market purchases are purchases of energy made on a short term basis rather than through a longer-term contract. A utility decides to buy spot energy from one or more suppliers based on economics and the availability of its generating units and firm purchased power contracts. Purchases of spot market energy are made in order to lower costs when the spot market price is below both the marginal cost of providing that energy from the Company's generating units and the Company's firm capacity purchases. Since the spot market depends on energy supply and demand in each hour, the prices tend to be much more volatile than firm purchased power. The Staff used a procedure developed by the Commission's Energy Department-Engineering Section in 1996 that is described in the document entitled "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market" (March 18, 1996). This method uses a statistical calculation based on the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.

The spot market price inputs for the calculation are based on actual hourly non-contract transaction prices in the twelve month period ending June 30, 2009. These were obtained from data the Company supplied to comply with 4 CSR 240-3.190. The Staff's methodology yields a spot energy price for each hour of the year. This data set containing 8760 hourly spot energy prices was used as one of the inputs to the Staff's RealTime™ fuel model by Staff witness Lange.

Staff calculated the spot purchased energy availability, using Empire's actual hourly non-contract transaction purchased demands in the period of twelve months ending June 30, 2009, obtained from the data Empire supplied to comply with 4 CSR 240-3.190, by finding each month's, hourly maximum purchase demand.

Staff Experts: Erin Maloney and Shawn E. Lange

4. Hourly Net System Input

Hourly Net System Input (NSI) is the hourly electric supply necessary to meet the hourly electrical energy requirements of Empire's customers and internal needs, excluding the electricity requirement of the company's generating plants. Empire's NSI is sensitive to weather conditions, in part, from customers' air conditioning systems and heating systems present in its service territory. Timing and magnitude of Empire's hourly NSI is correlated with and responsive to daily temperatures and temperature fluctuations: when the weather becomes hot or cold, the demand for electric energy changes in a measureable manner.

The hourly loads used in the analysis of the test year, July 2008 through June 2009, were provided by Empire in response to Data Request No. 132. Hourly load data submitted monthly by Empire in compliance with the Commission's rule 4 CSR 240-3.190 was used to cross check the data request response.

Daily actual and normal temperatures are a fundamental component of any weather impact analysis. During the test year the actual daily temperatures differed from those that would have occurred under "normal" conditions. Therefore, to reflect normal weather, daily peak net system loads (peak demand) and daily average net system usage (average usage) are considered independently, but using the same methodology because average loads respond differently to weather than do peak loads.

Average usage is calculated as the sum of each day's observed hourly NSI divided by twenty-four, i.e., the number of hours in a day. The peak demand is the maximum hourly usage for the day. Separate regression models, one for daily average usage and one for daily peak demand are used to determine the weather adjustment for each day. Staff witness Manisha Lakhanpal of the Energy Department provided actual and normal daily temperatures used to weather normalize NSI[13].

NSI is the sum of retail, wholesale and company usages together with losses in the transmission and distribution system. Staff totaled the weather normalized, annualized test year billing usage for both Missouri and non-Missouri retail customers, provided by Staff witness Curt Wells, the test year weather normalized, wholesale usage which was determined using the same process used to weather normal NSI, and company usage as provided by Empire in

[13] For more information, the process is described in greater detail in the document *Weather Normalization of Electric Loads, Part A: Hourly Net System Loads* (November 28, 1990), written by Dr. Michael Proctor, Manager of the Commission's then-Economic Analysis Department.

response to Data Request No. 132, were summed and adjusted for line losses by an annual factor provided by Staff witness Alan J. Bax. This sum is the normalized, annualized electricity requirement that corresponds with Staff's revenue requirement in this case. The weather normalized hourly NSI was adjusted by the ratio of this requirement to the sum of the weather normalized NSI to determine normalized, annualized hourly usage requirements at the generator.

Once completed, the test-year hourly normalized, annualized NSI and the hourly firm wholesale loads were given to Staff witness Shawn E. Lange to be used in developing the Staff's adjusted test year fuel and purchase power expense. Staff witness Alan J. Bax used the normalized, annualized NSI in developing the jurisdictional energy and demand allocators.

Staff Expert: Walt Cecil

a. Normal Weather

Please refer to the revenue section of this report (Section VIII. A. 3.) for a description of how Staff calculates normal weather.

b. 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 Empire's system between its generating sources and the customers' meters. In addition, small, fractional amounts of energy either diverted (stolen) or not metered are included as system energy losses.

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

NSI = Total Sales + System Energy Losses

NSI and Total Sales are known and measurable. System energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales

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

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

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 calculated the loss percentage of Empire's system, for the twelve months ending June 2009, as 6.73% of NSI. Staff witness Walt Cecil used this loss percentage in the development of hourly loads used in Staff's fuel model.

Staff Expert: Alan J. Bax

<u>5. Planned and Forced Outages</u>

Planned and forced outages are infrequent in occurrence, and variable in duration. In particular, forced outages are unplanned and can happen at any time. In order to capture this variability, the Empire generating unit outages were normalized by averaging the eleven years ending 2009 of actual values taken from responses to data requests, and data Empire supplied to comply with 4 CSR 240-3.190.

Staff Expert: Shawn E. Lange

E. Depreciation

Empire's current depreciation rates were ordered by the Commission in Case No. ER-2004-0570. Empire sought new depreciation rates in its last rate proceeding, Case No. ER-2008-0093, but the Commission ordered no changes to the Company's authorized depreciation rates in that case due to the pendency of Empire's Experimental Regulatory Plan, approved in Case No. EO-2005-0263.

Empire is seeking no change to its current authorized depreciation rates in this case, and the Staff recommends that the currently ordered depreciation rates remain in effect.

Staff Expert: David Williams

F. Payroll and Benefits

<u>1. FAS 87 and FAS 88 Pension Costs</u>

In Case No. ER-2004-0570 the Staff, Empire and other parties entered into a "Stipulation and Agreement as to Certain Issues," addressing, among other items, the ratemaking treatment for annual pension cost under Financial Accounting Standard (FAS) 87. This agreement, and thus treatment of annual pension cost, was later modified by the "Stipulation and Agreement as to Certain Issues" entered into in Case No. ER-2006-0315. This agreement was further and finally modified by the "Stipulation and Agreement as to Certain Issues," entered into in Empire's last Missouri rate proceeding, Case No. ER-2008-0093. These above-referenced agreements provide for Empire to have its pension rate allowance set equal to its most current annual level of pension expense as calculated under FAS 87. To the extent this pension rate allowance is greater than the Company's "minimum ERISA" annual pension funding requirement, then under the terms of the above-referenced agreements the excess amount is to be used to reduce Empire's Prepaid Pension Asset included in rate base. Furthermore, these agreements established a "tracker mechanism" for Empire's pension expense, in which any excess or deficiency in the Company's pension rate allowance as compared to its ongoing levels of FAS 87 expense is to be treated as a regulatory asset or liability. The resulting pension tracker regulatory asset or pension tracker regulatory liability is then to be included in Empire's rate base, and amortized as an addition or reduction to pension expense over a five-year period.

Pension cost under FAS 87 is reflected in the Staff's income statement in this case consistent with the ratemaking treatment agreed upon by the signatories to the stipulation and agreements approved by the Commission in Empire's last three electric rate cases. Empire's rate base, as determined by the Staff, includes the FAS 87 Regulatory Asset, which represents the difference between FAS 87 pension costs recovered in rates and FAS 87 pension costs recognized in the financial statements between rate cases.

1. The Company's ongoing FAS 87 cost recognized in rates in this case is $5,093,719

2. Empire has under-recovered its FAS 87 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Asset account at December 31, 2009, was $1,177,780 which is to be amortized over five years as a expense in the amount of $235,556.

3. The amount to be included in rate base is $1,177,780, as noted above.

Staff Expert: Paul R. Harrison

2. FAS 106 – Other Post Retirement Benefit Costs (OPEB's)

In Case No. ER-2006-0315, the signatory parties entered into a "Non-Unanimous Stipulation and Agreement as to Certain Issues," addressing the ratemaking treatment for annual other post-retirement benefit costs (also known as OPEBs) under Financial Accounting Standard (FAS) 106. OPEBs primarily relate to medical benefits owed to Company retirees. This agreement was later modified by the "Stipulation and Agreement as to Certain Issues" reached in Case No. ER-2008-0093. These stipulations and agreements were intended to ensure that the amount collected in rates for OPEBs is based on the FAS 106 cost recognized by the Company for financial reporting purposes, using a methodology similar to that used to determine FAS 87 pension cost. The above-referenced stipulations also called for use of an OPEBs "tracker mechanism" to quantify the difference over time in the OPEBs rate allowance provided to the Company and that Company's actual annual OPEBs expenses under FAS 106.

In this case, the Staff has complied with the terms agreed to in Case No. ER-2008-0093 for ratemaking treatment of OPEBs costs, and is recommending the following:

1. The Company's ongoing FAS 106 cost recognized in rates in this case is $552,484

2. Empire has over-recovered its FAS 106 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Liability account at December 31, 2009, was ($3,255,784) which is to be amortized over five years as a reduction to expense in the amount of ($651,157).

3. The amount to be included in rate base as a reduction is $3,255,784, as noted above.

Staff Expert: Paul R. Harrison

3. Supplemental Executive Retirement Plan (SERP)

Empire's SERP program is a pension benefit limited to Empire's officers and executives. Unlike Empire's regular pension plan, this program is unfunded; i.e., payments to its beneficiaries are not pre-funded through trust mechanisms. The Staff has consistently taken the position that rate recovery for plans such as SERP should be based upon actual payments to beneficiaries, and not based upon SERP expense accruals booked by the Company.

In this case, the Staff reviewed EDE's recurring cash SERP payments for the last five years. Since the level of cash SERP payments has not varied significantly over the previous five years, the Staff determined that the test year amount of these payments would be appropriate for this rate case.

Staff Expert: Paul R. Harrison

4. Payroll, Payroll Taxes and 401K Benefit Costs

The Staff has adjusted Empire's test year payroll expense to reflect an annualized level of payroll, payroll taxes, and 401(k) benefit costs as of December 31, 2009, the endpoint of the test year update period ordered for this case by the Commission.

Base payroll was calculated by multiplying employee levels at December 31, 2009, by the then-current appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll for Empire was calculated for each full-time hourly employee based upon an overtime percentage computed for non-union and union employees. The overtime percentage for each was calculated by (1) annualizing the five-year average of overtime hours actually incurred, (2) multiplying that by the current average December 2009 overtime rate, and (3) dividing the product by the Staff's pro forma base payroll amount. The Staff removed from its calculation of this average the overtime hours associated with the January and December 2007 ice storms, which resulted in significantly higher than normal amounts of employee overtime. After allocation between expense and construction, the adjustment for payroll was distributed by Federal Energy Regulatory Commission Uniform System of Accounts (FERC USOA) based upon the actual distribution experienced by Empire for the twelve months ending June 30, 2009, the end of the test year. The Staff's Accounting Schedule 10, Adjustments to the Income Statement, reflects seventy (70) adjustments, segregated by FERC USOA Accounts, to reflect Staff's total adjustment of $483,044 required to restate the test year payroll to an annualized level as of December 31, 2009.

The Staff calculated payroll taxes based upon December 31, 2009 wage levels and current tax rates. This included Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA), and Federal Insurance Contributions Act (FICA) tax. The Staff's annualized payroll and most current tax rates were used to calculate the level of payroll tax proposed in this case. In addition, FICA payroll taxes were computed for allowable non-financial incentive payments incurred in the test year. The Company's 401(k) benefit costs were annualized by applying Empire's actual 401(k) match rate for each employee to the annualized payroll as of December 31, 2009. The adjustments for annualized payroll taxes and 401(k) benefit costs appear as E-148.1, E-148.2, E-148.3, and E-126.5 in the Staff's Accounting Schedule 10.

Staff Expert Keith D. Foster

<u>5. Incentive Compensation</u>

As in Empire's recent rate cases, the Staff has reviewed Empire's portfolio of incentive compensation plans offered to its employees. Based upon this review, the Staff is proposing to disallow portions of the Company's test year incentive compensation expenses related to the Management Incentive Compensation Plan (MIP), lump-sum payments offered to certain employees called "Lightning Bolts," and equity incentive compensation offered to the Company's executives. These disallowances are not stated as separate income statement adjustments, but are embedded within the Staff's previously described seventy (70) payroll adjustments.

a. Management Incentive Compensation Plan (MIP)

Empire's MIP program offers awards to Empire senior officers for the achievement of goals. MIP awards were paid to Empire's officers in early 2009 for goals attained for calendar year 2008. Each senior officer had a list of goals pertaining to areas such as expense control, capital markets, regulatory performance, customer service, project completion, operations, financial performance, corporate governance, and safety. Each of these goals was given a specific performance measure and weighting, thus assigning a target cash payout. The amount of the award determination was based upon attainment of a specific performance level by the senior officer:

Threshold (50% of target payout)
Target (100% target payout)
Maximum (200% of target payout)

If the results for a specific goal were below the threshold, the senior officer did not receive an MIP award related to that specific goal. If the results were at or above the level set for the maximum goal, the senior officer received double the target MIP award for that specific goal.

Related to the MIP, the Staff eliminated the recovery of awards associated with meeting (but not exceeding) budgetary goals and any awards related to attainment of earnings goals. In the Staff's view, since financial goals directly benefit shareholders, shareholders should bear the cost of these incentives.

The Staff's position on this matter in this case is consistent with the Commission's disallowance of certain MIP expenses in the Commission's Report and Order in a prior Empire rate case, Case No. ER-2006-0315.

b. Lightning Bolts

Empire's "Lightning Bolts" program offers one-time incentive payments in the nature of bonuses to certain employees. The Staff is recommending a disallowance of the cost of these discretionary bonuses paid in the test year. The Commission's Report and Order in Case No. ER-2006-0315 adopted the Staff's recommended disallowance of short-term incentive compensation tied to discretionary bonuses that are unsupported by well-defined goals and for which the criteria for granting awards is not known in advance.

c. Equity Incentive Compensation

In Empire's past rate cases, the Staff also recommended a disallowance of long-term stock incentive compensation awarded to Empire's executive management resulting in the issuance of Empire's stock and performance shares for achievement of goals. Stock options are considered part of the senior officer's total compensation and are granted each year to the officers of the Company. The senior officers do not have any specific goals to meet in order to be granted these stock options. The senior officer can exercise the options after a three-year vesting period if the stock price is higher than at the time of the grant and the senior officer is still employed by the Company. Achievement of these goals benefits Empire's shareholders, not Empire's ratepayers. Additionally, unlike other expense recognition in the income statement, expense recognition for equity-based incentive compensation does not result in a cash outlay by Empire. The Staff has eliminated stock options recognized as an expense in the test year consistent with the Commission's Report and Order in Case No. ER-2006-0315.

Staff Expert: Keith D. Foster

G. Operations and Maintenance (O&M) Expense for Iatan 1 Air Quality Control System

The AQCS additions at Iatan 1 include a Selective Catalytic Reduction (SCR) system for the removal of nitrogen (NOx), a wet scrubber for the removal of sulfur dioxides (Sox), a fabric filter bag house for the removal of particulate matter, and powder activated carbon (PAC) for the removal of mercury. These additions were made in order to comply with Environmental Protection Agency (EPA) regulations and to ensure that total emissions from the Iatan site after the addition of the Iatan 2 generating unit would be less than emission levels prior to 2008 from a single unit. The O&M costs for the Iatan 1 AQCS consists of the annual replacement costs of limestone, ammonia and PAC used in the AQCS to meet environmental guidelines. The Staff's adjustment is based on the projected O&M budget Kansas City Power & Light has prepared for the Iatan 1 plant. Empire's ownership portion of the Iatan 1 AQCS is twelve percent. The Staff made an adjustment to its cost of service to include $350,008 for O&M expenses associated with Iatan 1 AQCS to account for a full year of operation of the AQCS. The Iatan 1 AQCS did not go into service until April of 2009; therefore it is necessary to make this adjustment to annualize the O&M expense for Iatan 1 AQCS.

Staff Expert: Paul R. Harrison

H. O&M Expenses for Asbury Selective Catalytic Reduction (SCR)

The SCR additions for Empire's Asbury generating station went into service in February of 2008, but because the EPA's new Clean Air Interstate Rule regulations for NOx emissions did not go into effect until January of 2009, the SCR did not operate at normal levels until January of 2009. The O&M costs for Asbury SCR consists of the annual replacement costs of ammonia used by the SCR to meet environmental guidelines. $354,000 was the actual amount of this costs incurred in the first six months of 2009; therefore an adjustment of $354,000 is needed to annualize the O&M expense for the Asbury SCR for a full twelve months of operation..

Staff Expert: Paul R. Harrison

I. Maintenance Normalization Adjustments

Empire's maintenance expenses for its generating facilities (production stations) tend to fluctuate from year to year, since unscheduled outages occur at irregular and unpredictable times, and major planned outages do not occur annually. Each maintenance account was reviewed and analyzed separately for each production station. The production facilities examined included Iatan 1, Asbury, Riverton, State Line Combined Cycle, State Line 1, and Energy Center 1 and 2. These units were examined individually because each of them is on a different maintenance cycle and to group them would have either overstated or understated the final annualized maintenance costs. These adjustments were then combined when possible in an effort to reduce the volume of adjustments.

1. Iatan

The Staff noted the Iatan 1 production station is on a six-year major maintenance cycle. For that reason, the Staff used a six-year average of maintenance costs. Empire owns only 12% of the Iatan 1 unit, with KCPL and KCPL-Greater Missouri Operations owning the remainder.

2. Asbury

The Asbury maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. The Staff's adjustment is based upon a five-year average of maintenance costs.

3. Riverton

The Riverton maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. The Staff's adjustment is based upon a five-year average of maintenance costs.

4. State Line Combined Cycle (SLCC)

Empire owns 60% of the SLCC unit, with Westar, Inc. owning the remaining 40%. Based upon the review of actual costs incurred by the Company under its contract with Siemens Westinghouse Power Corporation (Siemens) for the maintenance of the SLCC unit for the last five years, the Staff subtracted the amount of expenses incurred in the test year ended June 30, 2009, from the five-year average expenses to calculate the Staff's adjustment.

5. State Line 1 and Energy Center 1 and 2

Empire has had a contract with Siemens, related to the maintenance of these production units, since June 29, 2001. The terms of the contract require Siemens to conduct maintenance service for the turbines, which are required to run for a specified number of hours per year. If a turbine does not meet the hours requirement, a credit is due to Empire and, if the turbine exceeds the hours, then the Company incurs more costs. The nature of this expense varies greatly from year to year and, therefore, the Staff is recommending using a five-year average to normalize this expense. The actual test year amount is subtracted from the five-year average, to derive the Staff's adjustment.

6. Transmission and Distribution Maintenance

The Staff is proposing two adjustments to Empire's test year transmission and distribution (T&D) maintenance. The first is to add back to expense certain repair costs that were improperly deferred by Empire as part of its Commission Rules Tracker mechanism. This is further discussed in Rate Base Section VI. L. of this Report. Second, the Staff is proposing to include T&D costs associated with a May 2009 windstorm incident in expense which were deferred by Empire and booked to a regulatory asset account. Such treatment is normally only given to costs associated with "extraordinary items" or "extraordinary events," such as the Company's January 2007 and December 2007 ice storm events. Wind or ice storms that may inflict some level of damages to utility facilities are not necessarily extraordinary events, and only those storm events with an unusual and material impact on the Company's facilities and finances should be granted the extraordinary accounting and rate treatment of deferral of the expenses for future recovery from ratepayers. The Staff believes that the May 2009 windstorm does not financially rise to the level of the Company's 2007 ice storms and, accordingly, the cost of the windstorm should be reflected in rates as a normal, and not an extraordinary item of expense.

The Staff has requested information concerning Empire's historical T&D maintenance expenses. When this information is received, the Staff may propose additional adjustments to normalize the Company's test year maintenance expenses, if warranted.

Staff Expert: Keith D. Foster

J. Other Non-Labor Expenses

1. Rate Case Expenses

The Staff has included the actual costs incurred by Empire for rate case expense as of December 31, 2009, for this case (No. ER-2010-0130). The Staff's rate case expense adjustment is based upon all costs associated with filing and bringing this case before the Commission such as consulting fees, employee travel expenditures and legal representation. The ultimate amount of rate case expense incurred by the Company in this proceeding will be directly associated with the length of the case through the settlement conference and hearing process.

The Staff's adjustment removes from Account 928, Regulatory Commission Expense, all expenses booked in the test year associated with prior Empire Missouri rate proceedings. The Staff has proposed a separate adjustment to add back rate case costs associated with the current rate proceeding to Account 928. This adjustment includes the adjusted costs booked to Account 928 for Federal Energy Regulatory Commission (FERC) expenses and the PSC annual assessment.

The exclusion of prior rate case expenses from ongoing rate recovery is appropriate because the Staff's policy is to recommend recovery in rates of normalized rate case expenses only on a prospective basis. The Staff believes it is inappropriate to allow specific recovery in rates of amounts related to past rate proceedings. Also, the Staff does not agree that rate case expense is an item that should be "amortized" in a rate case, as that implies an obligation to allow recovery of any unamortized costs in the utility's next rate proceeding

The Staff will work with the Company through the duration of this case to establish a reasonable and ongoing normalized level of rate case expense for inclusion in rates. This means that any additional expenses associated with the processing of this rate filing by Empire will be examined to determine their appropriateness for inclusion in this case.

The Staff has chosen not to normalize Empire's rate case expenses over a multi-year period in this case, since the Staff expects that Empire will file another general rate case soon after this proceeding concludes, in order to obtain rate treatment of additional rate base investment now scheduled to be in-service in the fall of 2010.

The Staff has reviewed the Commission's Report and Order in Case No. GR-2009-0355, Missouri Gas Energy (MGE), regarding its discussion of rate case expense. In the MGE Order, the Commission made clear that recovery of rate case expense should not be viewed as a "blank check," and that utilities should recognize that rate case expense may not be reflexively and automatically passed on to customers. The Staff has reviewed Empire's rate case expenses incurred to date and its projected expenses for this case in that light, and believes that the Company's projected rate case expenditures for this proceeding appear to be reasonable in nature and in amount. The Staff will continue to monitor and audit Empire's claimed rate case expenses for prudence and reasonableness throughout the duration of this proceeding.

Staff Expert: Casey Westhues

2. Dues and Donations

The Staff reviewed the list of membership dues paid, and donations made, to various organizations that Empire charged to its utility accounts during the test year. The Staff proposes adjustments to exclude various dues and donations that were included by Empire in its above-the-line expense accounts. 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.

The Staff excluded dues and donations that do not have any direct benefit to ratepayers and were not necessary for the provision of safe and adequate service. Allowing the Company to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues excluded from recovery in the rate case are dues paid to the Home Builders Association, Rotary Club, Spiva Center for the Arts, etc. Examples of donations that were excluded include donations to Jefferson Elementary School and the City of Carl Junction. Area Chamber of Commerce dues were allowed, but National and State Chamber of Commerce dues were disallowed as being duplicative costs to the local Chamber of Commerce organizations.

Staff Expert: Casey Westhues

3. Edison Electric Institute (EEI) Dues

According to information obtained from the Edison Electric Institute (EEI) 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 a primary 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.

The question arises as to whether Empire's customers benefit from the legislative and regulatory/lobbying activities undertaken by EEI and funded in part by Empire. In Case No. ER-83-49, a Kansas City Power & Light Company rate increase case, the Commission stated its position that EEI 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.

Pending receipt of information from Empire that would attempt to quantify ratepayer benefits from its participation in EEI, the Staff removed EEI dues in the amount of $124,439 from Empire's cost of service.

Staff Expert: Casey Westhues

4. Insurance Expense

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 proposed an adjustment to annualize Empire's insurance expense to reflect the premiums paid as of December 31, 2009, the end of the update period. The total adjustment proposed is $313,968.

Staff Expert: Casey Westhues

5. Infrastructure - Tree Trimming (Vegetation Management)

During Empire's most recent rate case, Case No. ER-2008-0093, the Commission authorized Empire to set up a two-way tracker to account for any difference between Empire's incurred vegetation management (tree trimming) / infrastructure inspection costs compared to an estimated target annual amount of $8,575,000. . The Staff has proposed an adjustment to expense to amortize this asset over a five-year period. The amount of this amortization is $204,833.

For purposes of including an ongoing amount of vegetation management (tree trimming) / infrastructure inspection costs in this case, the Staff has adjusted the test year non-labor costs incurred by the Company in these areas to equal the expense incurred during the twelve months ending December 2009. The Staff's adjustment is in the amount of $531,058.

Because the Staff expects that Empire's cost of complying with the Commission's Vegetation Management and Infrastructure Inspection rules will continue to increase for the next several years, we are recommending that the Rules Tracker continue after this case. However, the Staff also recommends that labor costs no longer be included in the Tracker calculation, as the Staff's understanding is that Empire does not intend to create any more new employee positions to comply with the Commission Rules going forward.

The Staff has also included in its case an addition to Rate Base in the amount of the adjusted Commission Rules Tracker balance as of December 31, 2009. (see Section IV. L.).

Staff Expert: Paul R. Harrison

6. Customer Deposit Interest Expense

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

Staff Expert: Casey Westhues

7. Property Tax Expense

For property assessment purposes, utility companies are required to file a valuation of their utility property with their respective taxing authorities 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 its "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's adjustment was calculated by developing a property tax rate to be applied to total electric plant in service as of December 31, 2009. To develop the property tax rate, the Staff divided the amount of total property taxes due in calendar years 2005 - 2009 by the total plant in service for each year on January 1, 2005 to January 1, 2009. This property tax rate was then applied to total electric plant in service on December 31, 2009, to arrive at annualized property taxes. The annualized property tax expense was then subtracted from test year property tax expense to derive the adjustment. The Staff believes that the property tax expense arrived at in this manner is the best estimate available of ongoing levels of these taxes, and is consistent with how property taxes have been calculated for rate purposes in the past for Empire and other Missouri utilities.

Staff Expert: Casey Westhues

8. Bad Debt Expense

Bad debt expense is the portion of retail revenues that Empire is unable to collect from retail customers due to bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over for collection. However, Empire has been successful in collecting some portion of the delinquent amounts owed even after they are written-off. The Staff examining the actual seven-year (2003-2009) history of uncollectible write-offs that were never collected (i.e., write-offs net of amounts subsequently collected). It is apparent from the data that there is no upward trend in this item:

Description	Electric Retail Revenue - Net of Unbilled	Net Write-offs (Elec Only)	Effective Uncoll. Rate	Increase Decrease
YE 12/31/03	$ 297,007,058	$ 916,956	0.308732%	
YE 12/31/04	$ 296,818,747	$ 1,020,869	0.343937%	0.035205%
YE 12/31/05	$ 354,148,136	$ 1,327,612	0.374875%	0.030938%
YE 12/31/06	$ 377,411,833	$ 1,721,831	0.456221%	0.081346%
YE 12/31/07	$ 419,457,719	$ 3,027,689	0.721810%	0.265590%
YE 12/31/08	$ 390,396,758	$ 1,961,167	0.502352%	-0.219458%
YE 12/31/09	$ 411,132,067	$ 2,022,569	0.491951%	-0.010401%

From the information provided for the update period through December 31, 2009, an uncollectable percentage of the most current last five years was derived, which was then applied to the Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense. The Staff's adjustment for bad debt expense in the amount of ($190,310) adjusts the test year results to reflect a level of bad debt expense that is consistent with the Staff's annualized level of retail revenue.

Staff Expert: Paul R. Harrison

9. Advertising Expense

Empire engaged in advertising activities during the test year. Staff recommends recovery through rates of a level of expense related to advertising that is beneficial to ratepayers. In forming its recommendation of the allowable level of Empire's advertising expense, the Staff relied on the principles the Commission relied upon regarding Kansas City Power & Light Company in Case Nos. EO-85-185, et al..[14] The Commission recognized five categories of advertisements, and specified rate treatment for each of the following categories:

[14] Re: Kansas City Power and Light Company, 28 Mo. P.S.C. (N.S.) 228, 269-71 (1986).

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 and provided the rationale 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.

Staff's adjustment excludes the costs of institutional advertising from recovery in rates, in the amount of $29,859. Staff recommends recovery of the costs for safety advertising and general advertising directed towards the benefit of existing customers, unadjusted, in the amount of $111,890. Staff found no evidence that Empire engaged in any promotional or political advertising during the test year.

Empire conducts a customer opinion survey periodically, with surveys being conducted in 2004, 2006, 2008 and 2009. In this case, the Staff is proposing an adjustment to normalize the test year customer opinion survey costs over two years, in the amount of $6,000.

Staff Expert: Casey Westhues

10. Postage

The Staff annualized Empire's test year postage expense to reflect the postal increase that went into effect on May 11, 2009. The Staff included postal expense in the amount of $45,345 in its recommendation.

Staff Expert: Casey Westhues

11. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed. The Staff reviewed Empire's test year outside services expense booked to Accounts 923.005 through 923.514. The Staff normalized the amounts of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts in the amount of $32,047. This adjustment does not include outside services related to rate case expense. Outside services incurred for rate case purposes are booked in a separate account.

Staff Expert: Casey Westhues

12. Injuries and Damages and Workers' Compensation

Empire maintains workers' compensation insurance for the benefit of its employees. The Staff's workers' compensation adjustment annualizes this expense based upon the premiums in effect at December 2009 to reflect an ongoing and normal expense level for Empire of $178,100.

From time to time, Empire is sued by claimants seeking payment of damages. If Empire loses the lawsuit, it is likely to be required to make a payout to the aggrieved party, or it may choose to enter into out-of-court settlement, also resulting in a pay-out. Based upon generally accepted accounting standards, Empire is required to charge to current expense an estimate of its future payouts for injuries and damages claims. To determine a normalized level of this expense, the Staff used a three-year average of actual injuries and damages payments. A three-year average of payments was used because a historical analysis shows a considerable fluctuation in the annual amount of payments. Actual injuries and damages payouts were used to determine the Staff's adjustment, as opposed to Empire's expense accruals, as the Staff contends that the Company's estimates of future injuries and damages payouts are not known and measurable, and are not a suitable measurement for inclusion in rates.

Staff Expert: Casey Westhues

13. Employee Benefits

Empire currently offers its employees Dental & Vision, Healthcare and Life Insurance benefits. The Staff performed an analysis of the employee benefit costs included in Account 926 from the general ledger. The Staff annualized this expense by including the expense for each item through the end of the update period, which annualizes these expenses to reflect a full twelve months of the most recent financial information. The Staff's analysis indicates that healthcare, dental, vision and life insurance expenses are currently increasing slightly at Empire. This amount was compared to the test year level to determine the adjustment.

Staff Expert: Paul R. Harrison

<u>14. Gross Receipts Taxes</u>

The Staff has eliminated gross receipts taxes (otherwise known as city franchise taxes) from Empire's expenses. These taxes are merely a pass-through item from customers through Empire to the municipal taxing authorities. Empire bills and collects the taxes from its customers, and then in turn passes the taxes on to the municipal taxing authorities.

The Staff has also proposed an adjustment in an identical amount to remove franchise taxes from Empire's test year revenues, so that these taxes have no effect on the Company's revenue requirement.

Staff Expert: Paul R. Harrison

<u>15. Amortization Expense</u>

a. Amortization of Electric Plant

The Staff analyzed all amortization expense booked to Account 404.000, Amortization–Limited Term Electric Plant. The Staff's adjustment increased expense to reflect the annualized amortization based on updated information through December 31, 2009, (as described earlier in Section VI. H.).

Staff Expert: Paul R. Harrison

b. Amortization of Stock Issuance Costs

In 2006, 2007, 2008, and 2009, Empire made additional issuances of common equity, with the issuance in 2009 worth approximately $110,000,000. In making all of these issuances, the Company incurred costs totaling $6,126,190 (including incremental costs incurred by Empire to its equity distribution program since its inception) for its electric operations. It is the Staff's position that these costs be recovered through rates as an above-the-line adjustment to operating expenses. The Staff recommends that these costs be amortized over a five-year period for purposes of this proceeding.

Staff Expert: Paul R. Harrison

c. Amortization of Ice Storm Costs

In January and December 2007, two major winter storms that featured damaging freezing rain and heavy ice accumulation hit the Company's service area. Significant damage was caused to Empire's transmission and distribution systems by both storms. Because the restorative repairs were too extensive for Empire employees to handle on their own, the Company hired various contractors and employees from other utilities to assist in the restoration efforts. Empire tracked all costs associated with the ice storms separately. Some of these costs were capitalized and have been included in Empire's plant in service balances. For the amounts that were not capitalized, the Company requested in Case No. ER-2008-0093 that these expenses be amortized over five-years.

In that case, the Staff agreed with Empire that the costs incurred for the January and December 2007 ice storms were significant and extraordinary. Consistent with its past recommendations for rate treatment of the costs of extraordinary events, the Staff proposed to amortize these costs to expense over a five-year period, with no rate base treatment afforded to the unamortized balance. Consistent with past practice, the Staff also recommended that this amortization should be treated as having started within a reasonable time after the extraordinary expenses were incurred. In Case No. ER-2008-0093, the Company and the Staff entered into a "Non-Unanimous Stipulation and Agreement As To Certain Issues" and the language included in that Stipulation concerning the January and December 2007 ice storm costs is as follows:

> For purposes of future ratemaking, Empire shall be considered to have begun to amortize its January ice storm expenses in February 2007 and its December 2007 ice expenses in January 2008. Recognition of the expenses associated with the December 2007 ice storm will be given in this rate proceeding for a five-year amortization of prudently incurred costs in accordance with the treatment recommended in Staff's testimony for the January 2007 ice storm deferral amortization. The amount of annual amortization in this proceeding related to the December 2007 ice storm will be determined after the parties have had an opportunity to review Empire's quantifications and account treatment of its ice storm expenditures.

The Staff later reviewed Empire's quantifications and accounting treatment of its December 2007 ice storm expenditures in Case No. ER-2008-0093 and proposed an adjustment of $576,972 to amortize the Company's December 2007 ice storm costs over five years.

The Staff's recommended level of amortization expense in this case for the 2007 ice storms has been calculated consistently with the provisions of the agreements reached in Empire's prior rate case and amortized to expense over five years. Also, consistent with past Commission practice, the Staff did not include any portion of the unamortized portion of the extraordinary event deferrals in rate base. Utility shareholders and customers should share in the risk that such extraordinary events occur, and by not including the unamortized portion of the ice storm expenditures in rate base, these deferred costs will cause Empire to share in a portion of these costs (i.e., the time-value of money associated with rate recoveries from customers over a five-year period).

During this rate case audit, the Staff noted that Empire did not begin amortizing the costs of the January 2007 and December 2007 ice storms to expense for financial statement purposes until August 2008. This is in direct conflict with the terms of the Non-Unanimous Stipulation and Agreement As To Certain Issues reached in Case No. ER-2008-0093. This discrepancy has no impact on the amount of amortization expense included in this case related to the 2007 ice storms. However, in future rate cases the Staff intends to adjust ice storm amortization expense to reflect the stipulated end dates for the amortizations, not a July 2013 end date, as necessary.

Staff Expert: Paul R. Harrison

d. Regulatory Plan Amortization

Because Empire did not begin collecting the new amount of regulatory plan amortization authorized by the Commission in Case No. ER-2008-0093 until August 2008, the test year in this case of the twelve months ending June 2009 does not reflect a full year's expense for this amount. For this reason, the Staff has adjusted Empire's regulatory plan amortization expense to reflect a full twelve months of its current regulatory plan amortization in the Staff's determination of Empire's expenses for purposes of determining Empire's cost of service. For ease of presentation, the Staff removed the amount of regulatory plan amortizations included in Empire's test year depreciation expense, and then adjusted amortization expense to reflect a full year of these amortizations in the Staff's case.

Staff Expert: Mark L. Oligschlaeger

16. Demand Side Management Costs

Empire's Account 182.318 contains costs of the Company's Demand Side Management (DSM) programs that are in various stages of development and implementation. Based on the Staff's participation in the Customer Programs Collaborative (CPC) established to assist Empire in the development of DSM programs and the Staff's review of the costs in Account 182.318, the Staff has amortized the previously mentioned amounts over ten years in accordance with the terms of the Empire Experimental Regulatory Plan Stipulation and Agreement (Case No. EO-2005-0263). The DSM costs include the payments to Empire's customers that participate in the programs.

Staff Expert: Paul R. Harrison

a. Customer Programs Collaborative

The Commission's Order Approving Stipulation and Agreement in Case No. EO-2005-0263, established Empire's Experimental Regulatory Plan which includes the establishment of the Customer Programs Collaborative ("CPC") to make decisions (through a prescribed voting process) pertaining to Empire's affordability, energy efficiency and demand response programs ("Customer Programs"). Members of the CPC include Empire, Staff, Office of the Public Counsel ("OPC"), Missouri Department of Natural Resources and industrial interveners Praxair, Inc. and Explorer Pipeline Company. Each CPC member has one vote concerning any of the following activities/decisions: 1) Customer Programs objectives development; 2) consultant selection; 3) capacity balance and supply-side resource cost review; 4) design, screening and pre-implementation evaluation of potential Customer Programs; 5) Customer Program portfolio choice; and 6) post-implementation evaluation of Customer Programs. (*See* Order Approving Stipulation and Agreement, Case No. EO-2005-0263, (August 2, 2005), Attachment 1: Empire Experimental Regulatory Plan Stipulation and Agreement, pp. 25-30, July 18, 2005).

Empire witness Sherrill L. McCormack proposes in her direct testimony (page 11, lines 10 – 17) that there be: "a change in the status of the CPC to an advisory group rather than a group which has explicit voting rights." Ms. McCormack further states:

This would place Empire's collaborative group on a level consistent with the collaborative process employed at Kansas City Power & Light. Empire has gained experience in DSM programs over the last four years and has demonstrated a positive working relationship with all parties of the CPC. It is Empire's intention to continue in the same positive relationship, advising parties of ideas and asking for input to improve the process and programs. Empire does not believe it is necessary or efficient to retain the voting aspect of the current collaborative arrangement.

Staff agrees with Ms. McCormack's assertions that Empire has gained experience with DSM programs over the last four years and that Empire has demonstrated a positive working relationship with all parties of the CPC. Staff believes the CPC has been effective overall in meeting the objectives related to the selection, design, implementation and evaluation of Empire's Customer Programs. Staff is appreciative of the leadership of Ms. McCormack during the CPC process, at the CPC meetings, and at Empire to move Empire's Customer Programs in a positive direction.

However, Staff does not agree with Ms. McCormack that the voting aspect of the CPC is unnecessary. The voting aspects of the CPC is specifically defined in Empire's Experimental Regulatory Plan which does not expire until the effective date of the initial rates that reflect inclusion of the Iatan 2 investment, except where otherwise specified in the Empire Experimental Regulatory Plan. (See Order Approving Stipulation and Agreement, Case No. EO-2005-0263, (August 2, 2005), Attachment 1: Empire Experimental Regulatory Plan Stipulation and Agreement, p. 34, July 18, 2005). Although Empire's Iatan 2 investment is included in this case as filed by Empire, Empire has acknowledged that Iatan 2 will not be fully operational and used for service in time for this rate case. Therefore, it is premature to change any of the various aspects of the CPC. In order for Empire to remain within the provisions of the Empire Experimental Regulatory Plan Stipulation and Agreement, Empire needs to withdraw its proposal on voting. Staff recommends that the Commission not change the voting aspect of the CPC.

b. Amortization Period for Customer Programs Costs

The Commission's *Order Approving Stipulation and Agreement* in Case No. EO-2005-0263, approved Empire's Experimental Regulatory Plan which includes specific accounting and ratemaking treatment for Customer Programs costs:

> Empire shall accumulate the Affordability, Energy Efficiency and Demand Response Program costs in regulatory asset accounts as the costs are incurred. Beginning with the earlier of the date rates become effective in Empire's first Rate Filing within the term of this Agreement or March

> 27, 2008, Empire shall begin amortizing the accumulated costs over a ten (10) year period. Empire will continue to place the Affordability, Energy Efficiency and Demand Response Program costs in the regulatory asset accounts, and costs for each vintage subsequent to the first Rate Filing shall be amortized over a ten (10) year period. Signatory Parties reserve the right to establish a fixed amortization amount in any Empire rate case filed prior to June 1, 2011. The amounts accumulated in these regulatory asset accounts that have not been included in rate base shall be allowed to earn a return not greater than Empire's reduced AFUDC rate as specified in this Agreement.

(*See* Order Approving Stipulation and Agreement, Case No. EO-2005-0263, (August 2, 2005), Attachment 1: Empire Experimental Regulatory Plan Stipulation and Agreement, pp. 29-30, July 18, 2005).

Empire witness Sherrill L. McCormack proposes in her direct testimony (page 11, lines 2 - 9) that there be a: "reduction in the amortization period for deferred DSM costs from 10 years to 5 years." Ms. McCormack further states:

> This shorter amortization period of 5-years would make Missouri DSM cost recovery more like our other states. Both Arkansas and Oklahoma allow utilities to recover costs through a rider based on DSM program budgets. These states, unlike Missouri's DSM amortization period of 10-years, allow concurrent recovery of DSM costs. Many of the DSM costs incurred are for the administration and delivery of these programs and are ongoing costs which should be recovered at the time of program delivery.

Staff understands Empire's desire for more timely recovery of DSM costs. However, Empire's Experimental Regulatory Plan does not expire until the effective date of the initial rates that reflect inclusion of the Iatan 2 investment. (*See* Order Approving Stipulation and Agreement, Case No. EO-2005-0263, (August 2, 2005), Attachment 1: Empire Experimental Regulatory Plan Stipulation and Agreement, p. 34, July 18, 2005). Although Empire's Iatan 2 investment is included in this case as filed by Empire, Empire has acknowledged that Iatan 2 will not be fully operational and used for service in time for this rate case. Therefore, Staff believes it is premature to change the amortization period for deferred DSM costs. In order for Empire to remain within the provisions of the Empire Experimental Regulatory Plan Stipulation and Agreement, Empire needs to withdraw its proposal on amortization. Staff recommends the Commission not change the amortization period for DSM expenses.

Staff Expert: John Rogers

17. Abnormal or Non-Recurring Charges or Credits

During the test year, the maintenance contract Empire had with Tomorrow Now for the support of Empire's PeopleSoft software was terminated. Tomorrow Now went out of business in October of 2008 and as a result was required to pay Empire ($252,247) in contract termination fees. Empire replaced the contract with a similar maintenance contract with another vendor, but an adjustment is needed to remove the non-recurring pay-off amount from the test year. Additionally, during the test year, Empire made adjusting entries to reclassify Empire operating expenses to the Iatan II construction project per an agreement in Case No. ER-2008-0093 in the amount of ($443,744), as well as to correct prior years' accounts payable balances for purchased power in the amount of ($133,193). All of these abnormal, non-recurring credits need to be reversed and removed from the test year cost of service to represent a normal ongoing level of expense. These adjustments increase expense by $819,194.

Staff Expert: Paul R. Harrison

18. Banking Fees

The Staff is proposing an adjustment to annualize the cost associated with banking fees paid by the Company for its commercial lines of credit. The Staff annualized the cost of the United Missouri Bank (UMB) banking fees based upon the current expenditures for the syndicated bank line of credit as provided by the Company in its Response to Staff Data Request No. 0295.

During the most current five-year period ending December 31, 2009, Empire's banking fees have consistently trended upward. The Staff, therefore, used the amount of banking fees expense for the twelve months ended December 31, 2009of $1,160,628 as the normalized level for this expense. An offsetting adjustment of $21,178 was made to the cost of these banking fees by the amount of interest earned on overnight investments made by the Company during 2009. This methodology is consistent with the Staff's approach to this issue in past rate cases.

During a meeting in January between the Staff and the Company, the Company stated that they were entering into a new contract with UMB that would result in a significant increase to their annual banking fees expense. The Staff then submitted Data Request No. 0285.1, which asked for the new UMB contract and any other support for the claimed increase in this cost that the Company has in its possession. A determination will be made to whether the Staff's adjustment for banking fees should be revised when the Staff receives this information.

Staff Expert: Paul R. Harrison

19. Lease Expense

Lease costs are those costs incurred by Empire for the leasing of its equipment and office space. The Staff examined these costs for the test year, updated through December 31, 2009 and made an adjustment to annualize these costs in rates.

The Staff submitted Data Request No. 0014 to Empire asking for a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri electric operations, along with the test year lease costs and information concerning all changes to the lease amounts since July 1, 2008. The data from this response indicates that Empire's annualized test year lease expense was $185,877. The Staff used the annualized lease expense provided in this response to adjust Empire's lease expense. This annualization resulted in an increase in the level of Empire lease expense of $12,111.

Staff Expert: Paul R. Harrison

20. Carrying Costs for Iatan 1 Air Quality Control System (AQCS)

The Company has deferred its carrying costs (monthly depreciation and AFUDC interest rates) for its Iatan 1 AQCS investment into Account 182.308, Iatan Deferred Carrying Costs. This deferral of carrying costs on the Iatan 1 AQCS investment was authorized under Empire's Regulatory Plan, approved by the Commission in Case No. EO-2005-0263. Empire is proposing to amortize these carrying costs over the estimated useful life of the Iatan 1 AQCS, which is 56.275 years. The Staff used this amortization period and calculated an amortization amount of $48,344 for inclusion in this rate case, based upon the Company's deferred asset balance for this item of $2,720,536 at December 31, 2009.

Staff Expert: Paul R. Harrison

21. Experimental Low Income Program (ELIP)

Staff received a copy of the Empire District Electric Company's Report "An Evaluation of the Experimental Low Income Program," on February 24, 2010. At the time of this filing, Staff has not had adequate time to review and analyze the report to present a recommendation on the continuation, elimination, or modification of the ELIP, and any resulting effect on Empire's cost of service. Staff will present its analysis and any recommendations regarding ELIP in the Class Cost of Service and Rate Design Report that will be filed on March 9, 2010.

Staff Expert: Carol Gay Fred

K. Current and Deferred Income Tax

1. Current Income Tax

Current income tax for this case has been calculated by the Staff consistent with the methodology used in Empire's recent rate case, No. ER-2008-0093. Certain adjustments are made to net income to compute the current income tax expense. These adjustments begin by taking adjusted net income and either adding to or subtracting from net income various timing differences to obtain net taxable income for ratemaking purposes. The adjustments are the result of various book versus tax timing differences and their implementation under separate tax methods: flow-through versus normalization. The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current provision for income taxes. A federal tax rate of 35 percent and a state income tax rate of 6.25 percent were used in calculating EDE's current income tax liability. This composite tax rate is 38.39%. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different than the timing required by the Internal Revenue Service (IRS) in determining current taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

50% Meals and Entertainment

Contribution in Aid of Construction

Book Amortizations

Regulatory Plan Amortization

Subtractions from Operating Income:

Interest Expense – Weighted Cost of Debt X Rate Base

Tax Straight-Line Depreciation

Tax Depreciation-Excess

2. Deferred Income Tax Expense:

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for the calculation of current income tax payable to the IRS, the timing difference is given "flow-through" treatment.

When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated depreciation.

For most utilities, it is necessary to break out a utility's tax depreciation into two separate components: tax straight-line depreciation and excess tax depreciation. Tax straight-line depreciation is different from book straight-line depreciation due to the different tax basis of property allowed under the tax code. Excess tax depreciation differs from straight-line book depreciation due to the higher depreciation rates allowed in the early years of an asset's life under the current tax code. Most tax basis differences were eliminated for assets placed into service after 1986 due to the Tax Reform Act enacted that year.

Staff's standard deferred income tax adjustment consists of three components:

1. IRS Schedule M timing differences: contributions in aid of construction and advances for construction. These amounts are normalized consistent with Staff's calculation in the prior rate case filing.

2. The tax timing difference between tax straight-line depreciation expense and tax depreciation expense: This treatment is consistent with the normalization calculation in the previous rate case filing.

3. Excess deferred income taxes resulting from the 1986 Tax Reform Act, which created excess deferred tax amounts associated with depreciation timing differences: As

such, an amortization has been created to amortize excess deferred taxes created from the change in tax rates back to customers.

Normally a combination of the above three components make up the amounts recorded as deferred income tax expense.

The "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" in Case No. ER-2006-0315 regarding the Regulatory Plan Additional Amortization requires that the additional amortization be included in the straight-line tax depreciation amount used in normalizing the timing difference for accelerated tax depreciation. The Staff's deferred income tax calculation treats the Regulatory Plan Additional Amortization, approved in Case No. ER-2006-0315, as an increase in the straight-line tax depreciation deduction. This approach is consistent with the "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" approved in Case No. ER-2006-0315.

Staff Expert: Paul R. Harrison

IX. Regulatory Plan Amortizations

In Case No. EO-2005-0263, the Commission approved a "regulatory plan" for Empire, which featured several provisions intended to protect Empire's investment grade credit ratings during its period of projected heavy construction from 2005 through 2010, when the Iatan 2 generating unit was projected to come on-line. One of the more significant features of the Empire regulatory plan is the reflection of special "amortizations" in rates if Empire does not meet certain financial ratios in any general rate case filed prior to the rate case that reflects Empire's planned investment in the Iatan 2 unit. As previously discussed in Section IV of this Report, the Staff believes, and Empire concurs, that Empire will not be able to reflect its costs in the Iatan 2 generating unit in rates from this proceeding. Accordingly, the Staff has calculated a regulatory plan amortization (RPA) amount as part of its direct filing in this case, as required by Empire's regulatory plan. The background for the RPA mechanism is discussed in more detail in the direct testimony of Staff witness Mark L. Oligschlaeger.

The RPA calculation attached as Appendix C to the *Second Stipulation and Agreement as to Certain Issues* in Empire's last general rate case, Case No. EO-2008-0093, is set out in the format agreed to by the parties in that case. The Staff has followed an identical approach in its RPA calculation in this case, which is attached to this Report as Appendix 3.

The Staff obtained some of the inputs to the RPA calculation directly from Empire; namely the balances for the Off-Balance Sheet Adjustment (OBSA) debt equivalent amounts and the imputed OBSA depreciation expense amounts. The Staff has requested additional support for these numbers through a data request that is still outstanding from the Company as of the date of this filing. Based upon Empire's response to this data request, the Staff may revise some of the calculation inputs.

Appendix-3 shows that an additional amortization should be added to Empire's traditional revenue requirement to determine its total rate increase amount in this case, based on its adjusted financial results at year-end 2009. The amount of the additional amortization can be found at Line 90 of Appendix 3.

Staff Expert: Mark L. Oligschlaeger

X. Fuel Adjustment Clause (FAC)

Recommendations

For the purpose rendering a recommendation regarding Empire's Fuel Adjustment Clause ("FAC") in this case, Case No. ER-2010-0130, Staff has conducted a review of documents provided by Empire in Schedules WSK-4 through WSK-7 attached to the pre-filed Direct Testimony of Empire witness, W. Scott Keith. Staff believes that Empire has not complied with all of the requirements of 4 CSR 240-3.161(3). For Empire to comply with the requirements of 4 CSR 240-3.161(3)(B), Staff recommends that Empire provide to the Commission for approval a notice to customers which describes how fuel and purchased power costs pass through the FAC and are applied to the customers' monthly bills.

Following Staff's investigation into these documents, workpapers supporting Empire's Cost Adjustment Factor ("CAF"), review of fuel and purchased power prices, and review of Empire's credit rating, Staff hereby recommends that the Commission:

1. Modify Empire's FAC as recommended by Staff concerning:
    a) The form of electronic workpapers required to be provided by the Company to support its CAF filings;
    b) Deletion of true-up language in the prudence review section of the FAC tariff sheets;

c) Inclusion of revenues from Renewable Energy Credits as an off-set to costs in the calculation of Empire's CAF; and,

d) Change in base cost per kWh for the summer months of June through September and a change in base cost per kWh for all the other months.

2. Order Empire to provide to Staff, or to make available to Staff, any and all information and/or documents reasonably required to assist Staff during the performance of CAF, true-up and prudence reviews; and,
3. Order Empire to discontinue use of the word "Fuel Charge" on its customers' bills and to instead substitute the words "Fuel and Purchased Power Adjustment" in an effort to help reduce customer confusion.

Summary of Empire's Current FAC

In Empire's last rate increase case, Case No. ER-2008-0093, the Commission with its *Report and Order* issued July 30, 2008 authorized Empire a FAC. The primary features of the resulting, currently-effective FAC (original tariff sheet numbers 17 through 17C, with effective dates of September 1, 2008) include:

- Two 6-month accumulation periods: September through February and March through August;
- Two 12-month recovery periods: June through November and December through May;
- CAF rate filings to be made no later than April 1 and October 1; and
- A 95%/5% sharing mechanism.

Rebase of Cost of Fuel and Purchased Power

In the pre-filed Direct Testimony of Empire witness Todd Tarter, Empire recommends the Commission at this time extend its FAC without modifications to the base cost of fuel and purchased power energy. Staff is in the process of finalizing its fuel run and will discuss its analysis of rebasing the base cost of fuel and purchased power for Empire's FAC in the Staff Class Cost of Service Rate Design Report to be filed March 9, 2010.

Empire's FAC Sharing Mechanism

Empire has made two CAF rate filings since the Commission approved Empire's FAC. Empire made its first CAF filing (Case No. EO-2009-0349) on April 1, 2009. The first CAF filing was based on the accumulation period of September 1, 2008 through February 28, 2009. Empire's net base cost of fuel and purchased power during the first accumulation period were $75,211,342 and the total energy costs were $77,599,808, $2,388,465 above the net base fuel and purchased power costs for that period. With the 95% pass through mechanism and after adjustments for sales to wholesale customers and Empire's other jurisdictions, Empire retained 5% of the difference ($102,249) and the other 95% ($1,942,714) was collected from Empire's Missouri retail customers during the first recovery period June 1, 2009 through November 30, 2009, subject to true-up and prudence reviews.

Empire made its second CAF filing (Case No. ER-2010-0105) on October 1, 2009. That rate filing was based on the accumulation period March 1, 2009 to August 31, 2009. Empire's net base fuel and purchased power costs during the second accumulation period were $75,974,254 and the total energy costs were $74,904,898, $1,069,356 below the net base fuel and purchased power costs for that period. With the 95% pass through mechanism and after adjustments for sales to wholesale customers and Empire's other jurisdictions, Empire retained 5% ($43,823) of the difference and the other 95% ($832,640) is being returned to Empire's Missouri retail customers during the second recovery period December 1, 2009 through May 31, 2010, subject to true-up and prudence review.

Overall, the total difference in fuel and purchased power costs for the two accumulation periods (September 1, 2008 through August 31, 2009) after adjustments for sales to wholesale customers and Empire's other jurisdictions was a positive adjustment of $1,168,499, of which Empire retained 5% ($58,426) and of which Empire's Missouri retail customers are responsible for paying the 95% ($1,110,074). Please see Table MJB-1 below.

Table MJB-1

	Total Energy Cost	**Base Fuel and Purchased Power Cost**	**Difference Including Adjustments**	**Empire's 5%**	**Customers' 95%**
AP 1	$77,599,808	$75,211,342	$2,044,961	$102,249	$1,942,714
AP 2	$74,904,898	$75,974,254	$(876,462)	($43,823)	($832,640)
Total	$152,504,706	$151,185,596	$1,168,499	$58,426	$1,110,074

Table MJB-2 below shows a sample cost allocation for Empire's FAC based on the difference including adjustments for total energy cost and base fuel and purchased power costs charged to customers and the amounts absorbed by Empire for the accumulation periods (September 1, 2008 through August 31, 2009):

Table MJB-2

Cost Allocation for Empire's FAC		
Percent Recovered in FAC	**Dollars Recovered from Ratepayers**	**Dollars Absorbed by Empire**
100	$1,168,499	
95	$1,110,074	$58,426
90	$1,051,649	$116,849
85	$993,224	$175,275
80	$934,799	$233,700
75	$876,374	$292,125
70	$817,949	$350,550
65	$759,524	$408,975
60	$701,099	$467,400
55	$642,674	$525,825
50	$584,250	$584,250
45	$525,825	$642,674
40	$467,400	$701,099
35	$408,975	$759,524
30	$350,550	$817,949
25	$292,125	$876,374
20	$233,700	$934,799
15	$175,275	$993,224
10	$116,849	$1,051,649
5	$58,426	$1,110,074
0		$1,168,499

Staff is not recommending a change in the sharing mechanism as Empire has completed only two accumulation periods and not enough time has passed to determine if the sharing mechanism is inappropriate.

Extension of Empire's FAC

In its *Report and Order* issued by the Commission in Case No. ER-2008-0093 the Commission provided a three-prong test used to determine whether a cost or revenue change should be tracked and recovered through Empire's FAC:

> The Commission concluded that a cost or revenue change should be tracked and recovered through a fuel adjustment clause only if that cost or revenue change is:
>
> 1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
>
> 2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels; and
>
> 3. Volatile in amount, causing significant swings in income and cash flow if not tracked.[15]

Staff utilized the Commission's three-prong test to determine whether to recommend extension, modification or discontinuance of Empire's FAC. Table MJB-2 shows the generation resources by fuel type (including purchased power) from Staff's preliminary fuel run:

Table MJB-3

Empire Generation Resources By Fuel Type		
Fuel Type	**MWh**	**Dollars**
Coal	37.97%	26.99%
Natural Gas	22.94%	34.31%
Hydro	1.02%	N.A.
Purchased Power (Contract)	31.15%	28.86%
Purchased Power (Spot)	6.91%	9.84%

Review of this information shows that Empire continues to meet a significant percentage (44%) of its cost for energy with natural gas and spot purchased power.

Table MJB-3 displays Empire's spot purchased power beginning July 2001 through October 2009. The data was submitted by Empire as required by 4 CSR 240-3.190.

continued on next page

[15] *In the Matter of The Empire District Electric Company's Tariffs to Increase Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company*, Report and Order, Case No. ER-2008-0093, (July 30, 2008), Page 37.

Table MJB-4

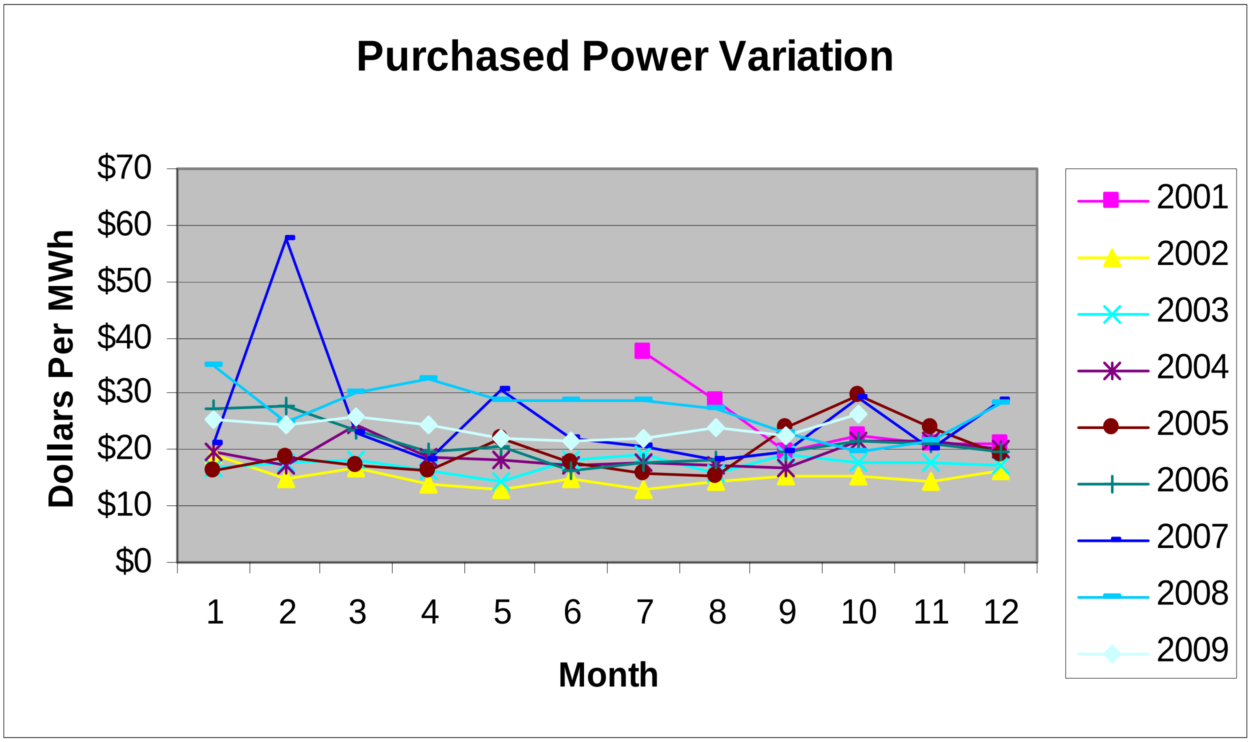
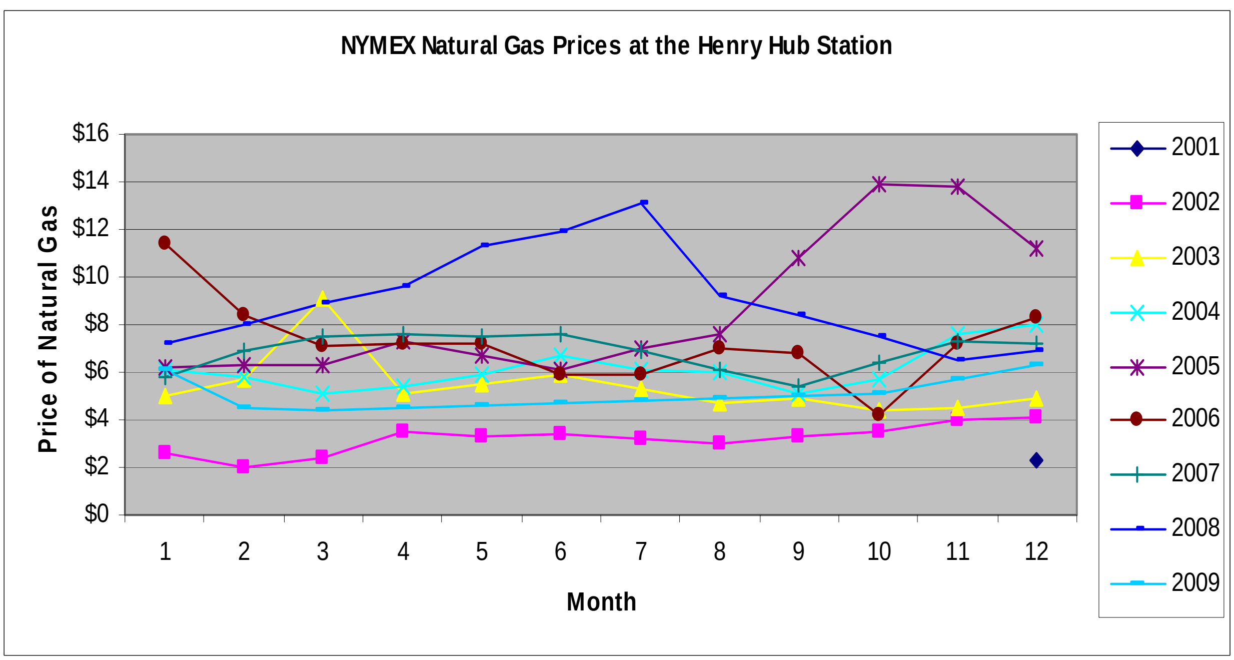


Table MJB-4 displays the market price of natural gas as reported by the New York Mercantile Exchange in Empire's response to Data Request No. 227 in its current rate case.

Table MJB-5



Review of natural gas prices and spot purchased power prices paid by Empire from 2001 through the first accumulation period of September 1, 2008 to February 28, 2009 and the second accumulation period of March 1, 2009 to August 31, 2009 demonstrate that the prices have fluctuated from year to year and from month to month.

The terms and structure of Empire's FAC is a vital component of Empire's credit rating. Standard and Poor's RatingsDirect currently rates Empire BBB-, one notch above non-investment grade or junk status, with a 'strong' business risk profile (business risk profiles are categorized as 'excellent', 'strong', 'satisfactory', 'fair', 'weak' and 'vulnerable') and an 'aggressive' financial profile (financial profiles are ranked from 'minimal', 'modest', 'intermediate', 'significant', 'aggressive' and 'highly leveraged'). A Standard & Poor's RatingsDirect article[16] dated January 28, 2010 states:

> Full realization of $22 million (6.7%) net electric rate increase in the fall of 2008 has helped to modestly strengthen the company's financial condition. <u>Importantly, the Missouri Public Service Commission (MPSC) granted a fuel adjustment clause (FAC) that enables the company to recover 95% of changes in fuel and purchased power costs in a timely manner, which is crucial for Empire's credit quality given its reliance on a relatively high level of natural gas-fired generation and purchased power</u>. Emphasis added.

Based on Staff's review of Empire's reliance on natural gas to meet is generating needs, the fluctuation of natural gas prices and spot purchased power prices that are beyond Empire's control because the prices for natural gas and spot purchased power are set by market forces, and the review of Empire's credit rating by Standard & Poor's, it is Staff's opinion that Empire meets the Commission's three-prong test to determine whether a cost or revenue change should be tracked and recovered through a FAC, but that Empire's current FAC should be modified. Therefore, Staff recommends that the Commission modify Empire's FAC as set forth above.

Additional Filing Requirements

In addition, to aid the Staff in performing CAF, prudence and true-up reviews, Staff recommends that the Commission order Empire to comply with the following terms and conditions:

[16] *Summary: Empire District Electric Co.*, Standard and Poor's RatingsDirect, January 28, 2010, a copy of which is attached as Appendix 4 and is incorporated by reference herein.

- Provide in the monthly reports required by 4 CSR 240-3.161(5), Empire's Southwest Power Pool (SPP) market settlements and revenue neutrality uplift charges;
- Maintain and provide for review at Empire's corporate headquarters or other location agreeable to Staff, a copy of all of Empire's nuclear fuel, coal, natural gas and transportation contracts that are or were in effect as of the date requested by Staff;
- Provide notice to Staff within 30 days of the effective date of all nuclear fuel, coal, natural gas and transportation contracts entered into by Empire;
- Provide Staff with complete copies of all present and future Empire hedging policies;
- Within 30 days of any change in an Empire hedging policy, provide and permit Staff to retain a complete copy of the changed hedging policy;
- Provide a complete copy and permit Staff to retain such copy of Empire's internal policy for participating in the SPP, including any Empire sales/purchases to or from the SPP market;
- If Empire revises any internal policy for participating in the SPP, within 30 days of that revision, provide and permit Staff to retain a copy of the revised policy with the revisions identified;
- In addition to supplying the information required by 4 CSR 240-3.190(3), provide to Staff the information for every incident at a power plant in which Empire has any ownership interest that involves serious physical injury or death or property damage in excess of $200,000 in the aggregate.
- Empire shall provide staff its Missouri Fuel Adjustment Interest Calculation workpapers in electronic format with all formulas intact when the Company files for a change in the Cost Adjustment Factor.

Staff Expert: Matt J. Barnes

Appendices:

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation

Appendix 3: Staff Regulatory Plan Amortization Calculation

Appendix 4: S&P Ratings Analysis of Empire

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))	Case No. ER-2010-0130

AFFIDAVIT OF SHANA ATKINSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Shana Atkinson, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 5-34; 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.

Shana Atkinson
Shana Atkinson

Subscribed and sworn to before me this 26th day of February, 2010.

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

Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))	Case No. ER-2010-0130

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Matthew J. Barnes, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 98-105; 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.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 25th day of February, 2010.

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 The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))	Case No. ER-2010-0130

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 49-50, 69-70; 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 25th day of February, 2010.

Susan L Sundermeyer

Notary Public

NOTARY PUBLIC
NOTARY SEAL
STATE OF MISSOURI

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

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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 53-54, 57 and 68-69; 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 26th day of February, 2010.

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

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF KEITH D. FOSTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith D. Foster, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 43-44, 61, 63-67, 73-75 and 77-78; 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.

Keith D. Foster

Subscribed and sworn to before me this 26th day of February, 2010.

Nikki Senn
Notary Public

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

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))	Case No. ER-2010-0130

AFFIDAVIT OF CAROL GAY FRED

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Carol Gay Fred, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 94-95; 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.

Carol Gay Fred

Carol Gay Fred

Subscribed and sworn to before me this 26th day of February, 2010.

Nikki Senn

Notary Public

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

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 35-36, 44-45, 46-48, 50-53, 58, 61-63, 70-73, 76, 82, 82-84, 86-89, 90, 93-94, 95-97 ; 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.

Paul R. Harrison

Paul R. Harrison

Subscribed and sworn to before me this 26th day of February, 2010.

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

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AFFIDAVIT OF 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 55-56, 57, 59; 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 26th day of February, 2010.

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

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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 64-65, 67, 70; 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 25th day of February, 2010.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

Susan L Sundermeyer
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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 67; 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

Subscribed and sworn to before me this 25th day of February, 2010.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
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In the Matter of The Empire District Electric	)	
Company for Authority to File Tariffs Increasing	)	Case No. ER-2010-0130
Rates for Electric Service Provided to Customers	)	
in the Missouri Service Area of the Company	)	

AFFIDAVIT OF MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Mark L. Oligschlaeger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-4, 48-49, 89, 97-98 ; 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.

Mark L. Oligschlaeger

Mark L. Oligschlaeger

Subscribed and sworn to before me this 26th day of February, 2010.

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

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of The Empire District Electric	)	
Company for Authority to File Tariffs Increasing	)	Case No. ER-2010-0130
Rates for Electric Service Provided to Customers	)	
in the Missouri Service Area of the Company	)	

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 90 - 92; 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 25th day of February, 2010.

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

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In the Matter of The Empire District Electric	)	
Company for Authority to File Tariffs Increasing	)	Case No. ER-2010-0130
Rates for Electric Service Provided to Customers	)	
in the Missouri Service Area of the Company	)	

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 56-57, 60-61; 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 25th day of February, 2010.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
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Susan L Sundermeyer

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AFFIDAVIT OF CASEY WESTHUES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Casey Westhues, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 34-43, 45-46 and 77-86; 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.

Casey Westhues
Casey Westhues

Subscribed and sworn to before me this 26th day of February, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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AFFIDAVIT OF DAVID WILLIAMS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Williams, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 70 ; 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 Williams
David Williams

Subscribed and sworn to before me this 26th day of February, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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