MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

FILE NO. ER-2011-0004

Jefferson City, Missouri
February 23, 2011

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COST OF SERVICE REPORT

I. Executive Summary

The Staff has conducted a review in File No. ER-2011-0004 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's" or "Company's") Missouri jurisdictional revenue requirement. This audit was performed in response to Empire's application to increase its Missouri jurisdictional retail rates by approximately $36.5 million, exclusive of applicable gross receipts, sales, franchise or occupational fees or taxes, filed on September 28, 2010.

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 November 30, 2010. Major elements of the revenue requirement calculation for Empire were measured through November 30, 2010, in the Staff's case. The Staff's audit results for Empire at the midpoint of its return on equity range (ROE) of 9.10% would be a rate increase of $579,943.[1]

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 16, 2011.

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. As of July 31, 2010, Empire served approximately 168,700 retail electric customers throughout its system of which approximately 149,500 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").

[1] During the finalization of Staff's Accounting Schedules it became apparent that there was an uncertainty of how some of Empire's plant balances should be properly quantified. Staff has included an allowance in its Revenue Requirement to address this concern.

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 File No. ER-2010-0130. Through its Order dated May 19, 2010 in that proceeding, the Commission granted Empire a total net increase in rates of $46,800,000. Of that amount, $36,800,000 was granted through a traditional revenue requirement approach, with the remainder resulting from additional amount of amortizations included in Empire's rates pursuant to its regulatory plan of $10,000,000. These amortizations will be described in more detail later in this Cost of Service Report ("Report"). File No. ER-2010-0130 was resolved entirely by the Commission's adoption of several stipulations and agreements in that proceeding, in particular the stipulations filed with the Commission on May 12, 2010 and August 16, 2010, respectively.

This rate case is the last to be covered under the terms of the "regulatory plan" approved for Empire in Case No. EO-2005-0263 by the Commission, and is the case described in Section III.D.7(a) of Empire's regulatory plan.[2] In this case, Empire is seeking to include in rates in investment in the Iatan 2 coal generating unit. While a majority of Empire's investment in the Plum Point coal generating unit and the Iatan 1 Air Quality Control System (AQCS) environmental addition were reflected in rates in the Company's last case, File No. ER-2010-0130, Empire seeks to recover a portion of the remainder of those units' costs in this rate case. In addition, the Staff has performed prudence audits of the owners' construction activities in this case in relation to the costs of the Iatan 1 AQCS, Iatan 2, Iatan common plant, and Plum Point projects incurred through October 31, 2010.

III. Test Year/Update Period/True-Up

Empire filed its case based upon a June 30, 2009 test year, with adjustments to reflect the impact of various material events it expected to occur through December 31, 2010. Empire's proposed test year was the same test year authorized by the Commission in the Company's prior electric proceeding, File No. ER-2010-0130. While it is unusual for the same test year to be used

[2] This was stipulated in the *Stipulation and Agreement* filed February 25, 2010, in File No. ER-2010-0130.

in consecutive rate increase filings, Empire advocated this approach in an effort to limit the number of new issues that might arise in the context of File No. ER-2011-0004.

In the *Joint Proposal Regarding Certain Procedural Matters* filing made with the Commission on November 15, 2010, the Staff and other parties concurred with Empire's recommendation for a test year of the twelve months ending June 30, 2009. The parties further agreed to use an update period in this proceeding of July 1, 2009, through November 30, 2010. No true-up proceeding was recommended in this filing, though parties are free to request one at a later stage of the proceeding if they believe it appropriate. Notwithstanding the test year update cut-off of November 30, 2010, the parties also agreed not to oppose inclusion of a non-union wage increase granted to Empire's non-executive employees in December 2010 in Empire's cost of service on the grounds that such increase was granted after the end of the test year update period.

In this proceeding, the Staff has updated all of the most material areas of Empire's revenue requirement through November 30, 2010, with the exception of the plant in service balances associated with the Iatan 1 AQCS, the Iatan 2 unit, Iatan common plant, and the Plum Point unit. Those expenditures were cut off at October 31, 2010, because the Staff's construction audits of those projects only covered expenditures made through the end of October. Also, as previously discussed, the Staff has incorporated the Company's December 2010 non-union salary increase in its recommended revenue requirement for Empire. At this time, the Staff does not believe a true-up audit is necessary for Empire in this proceeding.

Empire filed its request using Staff's accounting schedules in File No. ER-2010-0130 as a starting point.[3] By filing in this manner, Empire calculated its requested revenue requirement in File No. ER-2011-0004, by first incorporating the Staff's adjustments to Income Statement items (revenues and expenses) from the last Empire rate case into its starting point for the instant rate case. Therefore, to the extent that Empire disagreed with a Staff adjustment from File No. ER-2010-0130, or believed the numbers in the Staff's Income Statement from the last case should be updated beyond December 31, 2009[4], then Empire has proposed further adjustments in its request in this case.

[3] While this set of accounting schedules were never directly filed in EFIS in File No. ER-2010-0130, these accounting schedules formed the quantification of the Staff's revenue requirement differences with other parties in the *Reconciliation* filed with the Commission on April 28, 2010, and were distributed to the parties in that matter.

[4] December 31, 2009 was the end of the test year update period in File No. ER-2010-0130.

Staff does not object to this approach, and will likewise sponsor adjustments using the Staff's Income Statement from File No. ER-2010-0130 as a starting point for determination of its revenue requirement recommendation for Empire. For those items the Staff has found its Accounting Schedules in File No. ER-2010-0130 still reflects the appropriate amount of revenue, expense, or investment, it has not proposed any further adjustment. However, if the Staff found that the amounts for a given item in its Accounting Schedules from File No. ER-2010-0130 is no longer appropriate estimations of the ongoing level of revenue, expense, or investment, Staff has proposed further adjustments to its File No. ER-2010-0130 results.

There are certain costs of service elements in the Staff's Accounting Schedules for File No. ER-2010-0130, for which Empire accepted the File No. ER-2010-0130 adjustments and Staff recommends no further adjustments. Accordingly, the Staff has not included sections addressing these areas in this direct filing. These areas include:

Dues and Donations
Edison Electric Institute/Lobbying Costs
Insurance Expense
Advertising Expense
Postage Expense
Outside Services Expense
Injuries and Damages Expense
Workers Compensation Expense
Non-Labor Maintenance Expenses
Miscellaneous Expense Adjustments
Medical/Dental Benefits
Supplemental Executive Retirement Plan Benefits
Corporate Allocations
Jurisdictional Allocations

IV. Major Issues

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

Iatan 1 and 2 Construction Costs – The Staff has proposed significant and various disallowances to the cost of these plant additions, for the reasons stated in the separately filed construction audit reports submitted in the case concurrently with this Report.

Return on Equity (ROE) – The Staff has recommended a 9.10% ROE at the midpoint. Empire is recommending a 10.6% ROE. This issue is addressed in detail in the Section V of this Report.

Depreciation – The Company recommended an overall increase in Empire's authorized depreciation rates. Empire is also seeking inclusion of an amortization of an alleged depreciation reserve deficiency associated with the Riverton coal-fired generating units. The Staff has recommended no change in Empire's current authorized rates, and is not recommending inclusion of the Riverton Station reserve deficiency amortization in customer rates. Staff is proposing that the Iatan 2 plant accounts be segregated from the remainder of Empire's generation fleet and be assigned new depreciation rates in this proceeding.

Fuel and Purchased Power – The Company is not seeking any change ("rebasing") to the current level of fuel and purchased power expense included in its base rates. The Staff has calculated an ongoing level of fuel and purchased power expense in this case, and is recommended rebasing Empire's base fuel costs in this proceeding. The Staff's recommended level of expense in this area is significantly lower than the fuel and purchased power component contained within the Company's current rate levels.

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.

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

V. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return (ROR), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital (WACC), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis. Staff's expert financial analyst, Shana Atkinson, has determined Empire's cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, net of any risk adjustments, together with other capital component information as of November 30, 2010, to calculate Empire's fair rate of return, as follows:

TABLE ONE: Empire's ROR:

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.60%**	**9.10%**	**9.60%**
Common Stock Equity	49.36%	-----	4.24%	4.49%	4.74%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	50.64%	6.36%	3.22%	3.22%	3.22%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
Total	**100.00%**		**7.46%**	**7.71%**	**7.96%**

See Schedule 16

As reflected in the above table, Staff recommends, based upon its expert analysis, a return on common equity ("ROE") range of 8.60% to 9.60% and an overall ROR range of 7.46% to 7.96%, with a mid-point ROE and ROR of 9.10% and 7.71%, respectively. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-17. Additionally, with the exception of sources in which Staff simply extrapolated data and textbook references, supporting articles and/or reports are attached as Appendix 2, Attachments A - G. If the Commission discovers any additional supporting documentation it desires the Staff to provide, Staff will do so upon the Commission's request.

B. Analytical Parameters

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

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

Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co*., the Court stated:[5]

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

[5] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

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

1. A return consistent with returns of investments of comparable risk;
2. A return sufficient to assure confidence in the utility's financial integrity; and
3. A return that allows the utility to attract capital.

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

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions. [6] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return Empire's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific discounted cash flow (DCF) method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[7] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for Empire.

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

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

In this case, Staff has applied this comparable company approach through the use of both the DCF and the capital asset pricing model ("CAPM") method. Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***.

C. Current Economic and Capital Market Conditions

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

1. Economic Conditions

The United States is emerging from the most severe recession since the Great Depression. Although the economy is now again expanding, growth is projected to be lower in the long-term as compared to the growth rates achieved during the post World War II era before the recent recession. Economists generally expect the long-term nominal Gross Domestic Product ("GDP") growth rate to be in the range of 4% to 5%.[8] These projected long-term nominal GDP growth rates generally are predicated on 2% expected inflation as measured by the GDP price deflator.

The Federal Reserve Bank ("Fed") continues to maintain the Fed Funds Rate at historically low levels between 0.00% and 0.25% (*see* Schedules 2-1 and 2-2). Additionally, the Fed made a unanimous decision in its recent meetings on January 25 and 26, 2011 to continue its bond buy-back program in order to provide continued liquidity to the financial system. According to a *Wall Street Journal* (WSJ) article[9], the Fed specifically stated that "the economic

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

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

recovery is continuing, though at a rate that has been insufficient to bring about a significant improvement in labor market conditions." The Fed also stated that "longer-term inflation expectations have remained stable" and core inflation has been "trending downward." The Fed stated that it expected to hold short-term interest rates at its current level for "an extended period," which many investors interpret as continuing until at least early 2012.

Consequently, while there is much debate regarding the effect current monetary policy may have on inflation, it appears that the Fed's primary concern is still lack of sustainable growth in the economy. According to another *WSJ* article,[10] Ben Bernanke, the Federal Reserve Chairman, dismissed worries about inflation and concerns about rising yields on U.S. Treasury bonds. The article specifically stated the following regarding Ben Bernanke's testimony to congress:

> 'Inflation made here in the U.S. is very, very low,' he [Bernanke] said, even though it is picking up abroad. The unemployment rate isn't likely to fall back to desirable levels between 5% and 6% for four years at the earliest, he added, and could take as long as 10 years given present economic growth rates. 'I'm not concerned' about the rise (on U.S. Treasury bond yields), he said. These yields sometimes rise when investors are getting worried about inflation and demand a higher return as compensation.

Additionally, Mr. Bernanke stated that the recent yield increase, "primarily reflects more optimism about economic growth."

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets continue to indicate a lower cost-of-capital environment. If one were to assume that the risk premium[11] required to invest in utility stocks rather than utility bonds was constant, then these lower utility debt yields clearly translate into a lower required return on equity. In other words, a lower cost of debt is indicative of a lower cost of capital, all else equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Although long-term interest rates, as measured by 30-year Treasury

[10] Jon Hilsenrath and Luca Di Leo, "Bernanke Tries to Soothe GOP," *Wall Street Journal*, February 10, 2011, p. A5 (Attachment G).

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

bonds ("T-bonds"), had decreased to the high 3 percentage range during the months of July through October 2010, they have since increased to levels that were experienced from mid-2009 through mid-2010. (*see* Schedules 4-2 and 4-3). If 30-year T-bond yields persist at this level, then they will be more similar to the yields experienced for most of the past decade, absent the credit crisis in late 2008 and early 2009.

Long-term utility bond yields have also continued to more closely track the changes in the 30-year T-bond yields in the last few months. For instance, long-term utility bond yields increased with 30-Year T-bonds for the most recent three months through January 2011. This was after reaching a 40-year low of approximately 5.10 percent in August and September 2010. (see Schedules 4-1 and 4-3). As of January 2011, the average spread between 30-year T-bonds (4.52%) and average utility bond yields (5.69%)[12] was 117 basis points, which is 37 basis points below the average such yields displayed in the period since 1980 (*see* Schedule 4-4).

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

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

b. Utility Equity Markets

For the twelve months ended December 31, 2010, the total return on the Dow Jones Industrial Average was 14.1%, the total return on the S&P 500 was 15.1%, and the total return

[12] The 5.69% yield is based on an average from data obtained from BondsOnline.com. For utility bond yields cited by Staff prior to December 2010, Staff used Mergent Bond Record.

on the Edison Electric Institute (EEI) Index of electric utilities was 7.0% (*see* Appendix 2, Attachment B). More specifically on a non-market capitalization weighted basis, the total return for the twelve months ended December 31, 2010 was 15.8% for EEI "Regulated" electric utilities, 8.5% for EEI "Mostly Regulated" electric utilities and -5.2% for "Diversified" electric utilities.

Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely to be more affected by general economic trends. The higher total return for "Regulated" electric utilities compared to broader markets and "Diversified" electric utilities implies that investors do not expect a significant economic recovery in the near future. Consequently, assuming investors in "Regulated" electric utilities have not increased their growth expectations for the regulated utility sector, these higher returns imply a decrease in the cost of equity for "Regulated" electric utilities.

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

> The stocks face another, paradoxical headwind: hope. Regulated utilities, with high, stable dividends, often are treated as bond proxies, a big reason for outperforming other utilities since early 2009. As broader optimism rises, however, so should debt yields, making regulated utility stocks relatively less attractive. Making them sexy again won't be easy when even a $13.7 billion merger doesn't set pulses racing.[13]

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

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

D. Empire's Operations

The following excerpt from Empire's Form 10-K filing with the Securities and Exchange Commission ("SEC") for the 2010 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.
>
> Our gross operating revenues in 2010 were derived as follows:

Electric segment sales*	89.6%
Gas segment sales	9.4
Other segment sales	1.0

*Sales from our electric segment include 0.3% from the sale of water.

> 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 2010 retail electric revenues, approximately 88.9% came from Missouri customers, 5.3% from Kansas customers, 3.0% from Oklahoma customers and 2.8% from Arkansas customers.
>
> We supply electric service at retail to 120 incorporated communities as of December 31, 2010, 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 49% of our electric operating revenues in 2010 were derived from incorporated communities with franchises having at least ten years remaining and approximately 21% 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 2010 were derived as follows:

Residential	42.4%
Commercial	30.3
Industrial	14.4
Wholesale on-system	4.0
Wholesale off-system	4.7
Miscellaneous sources*	2.6
Other electric revenues	1.6

* primarily public authorities

Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2010 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2010.

Our gas operations serve customers in northwest, north central and west central Missouri. We provide natural gas distribution to 44 communities and 314 transportation customers as of December 31, 2010. 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. Seventeen of the franchises have 10 years or more remaining on their term. Although our franchises contain no renewal provision, since our acquisition, we have obtained renewals of all our expiring gas franchises prior to the expiration dates.

Our gas operating revenues in 2010 were derived as follows:

Residential	63.4%
Commercial	26.2
Industrial	1.6
Other	8.8

No single retail customer accounted for more than 3% of gas revenues in 2010.

Our other segment consists of our fiber optics business. As of December 31, 2010, we have 92 fiber customers.

E. Empire's Credit Ratings

Empire is currently rated by Moody's and S&P. It is important to understand the current credit standing of the Company, as these ratings influence investors' views of the risk associated with investing in Empire.

Empire's Moody's corporate credit rating is 'Baa2' and its S&P corporate credit rating is 'BBB-'.[14] While each rating is classified as "lower medium grade", S&P's rating is only one notch above junk status, i.e. non-investment grade.

The following is an excerpt from a January 3, 2011, S&P credit-rating report on Empire:

> The ratings on Joplin, Mo.-based utility Empire District Electric Co. reflect an excellent business risk profile (business risk profiles are categorized as excellent to vulnerable) and an aggressive financial profile (ranked from minimal to highly leveraged). Empire's business risk profile benefits from a diverse service territory with limited industrial concentration (approximately 15% of total retail load), a straightforward integrated utility business model, and from a cost-conscious management team. Although sales growth has moderated and customer growth is at a low rate, the service area economy remains healthier than other regions in the country. These characteristics are tempered by a historically challenging regulatory environment in Missouri, which we view as "less credit supportive." However, the Missouri Public Service Commission (MPSC) appears to be becoming more responsive to the company's rate needs, as evidenced by approval of settlement agreements and implementation of fuel adjustment clause (FAC) that enables the company to recover 95% of changes in fuel and purchased power costs in a timely manner. This is crucial for Empire's credit quality given its reliance on a somewhat high level of natural gas-fired generation and purchased power.
>
> Although Empire's key financial metrics will continue to be pressured this year due to rising costs and heavy outlays for its construction program, financial performance should begin to strengthen when capital spending winds down in 2011. In addition, completion of Empire's $120 million equity distribution program in 2010, full realization of recent rate relief and expectations for additional rate increases in 2011, coupled with cost containment efforts should help to lift bondholder protection parameters.

F. Cost of Capital

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

[14] Empire's 2010 SEC Form 10-K filing for the year ended December 31, 2010, p. 17.

1. Capital Structure

Schedule 5 presents Empire's historical capital structures in dollar terms and percentage terms for the past five years.

Staff used the actual, consolidated capital structure of Empire as of November 30, 2010, as the basis for its capital structure recommendation. Schedule 7 presents Empire's capital structure and associated capital ratios. The Staff's resulting ratemaking capital structure recommendation consists of 49.36 percent common equity and 50.64 percent long-term debt.

2. Embedded Cost of Debt

Staff's embedded cost of long-term debt of 6.36 percent is based on information provided by Empire in response to Staff Data Request Nos. 0099.1 and 0101.1. Staff's embedded cost of long-term debt is slightly lower than that provided by Empire because Staff proposes to disallow the remaining unamortized expense balance of approximately $1,133,570 associated with Empire's $1.6 million of debt expenses incurred to amend its mortgage bond indenture in order to allow it to maintain its current dividend per share of $1.28. Ratepayers should not be burdened with explicit costs associated with Empire's desire to continue to pay the current dividend level to its shareholders. Staff subtracted this amount from Empire's cost of debt calculation for the period ending November 30, 2010. Staff provides the underlying details of its embedded cost of debt estimate in Schedule 6.

3. Cost of Common Equity

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

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 58 market-traded electric utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to Empire's regulated electric utility operations (*see* Appendix 2, Schedule 8):

1. Classified as an electric utility company by Value Line (58 companies);

2. Publicly-traded stock;

3. Followed by EEI and classified as a regulated electric utility (23 companies eliminated, 35 remaining);

4. Followed by AUS and reporting at least 70% of revenues from electric operations (9 companies eliminated, 26 remaining);

5. Ten years of Value Line historical growth data available (3 companies eliminated, 23 remaining);

6. No reduced dividend since 2007 (5 companies eliminated, 18 remaining);

7. Projected growth available from Value Line and Reuters (2 companies eliminated, 16 remaining);

8. At least investment grade credit rating (2 companies eliminated, 14 remaining);

9. Company-owned generating assets (2 companies eliminated, 12 remaining); and

10. Significant merger or acquisition announced in last 3 years (2 companies eliminated, 10 remaining).

This final group of 10 publicly-traded electric utility companies ("the comparables") was used as a proxy group to estimate the cost of common equity for Empire's regulated electric utility operations. The comparables are listed on Appendix 2, Schedule 9.

b. The Constant-growth DCF

Next, Staff calculated Empire's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[15] [16] It may be expressed algebraically as follows:

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

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the 2011 Value Line projected dividend per share (*see* Schedule 12) by the monthly high/low average stock price for the three months ending January 31, 2011 (*see* Schedule 11).[17] Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.5%, unadjusted for quarterly compounding.

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share (DPS), earnings per share (EPS) and book value per share (BVPS) for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite volatile.[18] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 10-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 9.50%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 11.80%.

[16] 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.

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

[18] Schedule 10-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 10-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

The average projected 5-year EPS growth rate yielded a non-sustainable growth rate of 6.04% (*see* Schedule 10-4, Column 6).

Due to the current volatility and wide dispersions present in Staff analysis of historical and projected DPS, EPS, and BVPS, Staff considered none of those methods to produce reliable indicators of long-term growth expectations. For this reason, Staff selected an alternative input, based upon Staff's expertise and understanding of current market conditions. Staff used a growth rate range of 4.0% to 5.0% in its constant-growth DCF, although Staff does not consider that figure to be sustainable for the electric utility industry in the long run. According to data published in the *2003 Mergent Public Utility and Transportation Manual*, electric utility growth rates have been approximately half of achieved GDP growth for the period 1947 through 1999.[19] As noted previously, long-term nominal GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities should be much lower than the projected 5-year EPS growth rates.

Staff also analyzed the growth of electric utilities identified by Value Line as Central region electric utilities over the period 1968 through 1999, a shorter, more recent period based on data from Value Line rather than Mergent (Staff will explain this analysis in more detail when explaining its multi-stage DCF analysis). Staff's analysis of this data revealed that the actual realized growth of these electric utilities was less than half of GDP growth over this time period. In addition, this analysis also showed that during a period of much higher nominal GDP growth, the Central region electric utilities' EPS, DPS and BVPS grew in the range of 3.18% to 3.99% (see Schedules 14-1 through 14-4). Because the constant-growth DCF will only provide reliable results if the growth rate is within 1.0% to 2.0% of a sustainable long-term industry growth rate20, Staff decided its analysis of historical growth in the electric utility industry could only marginally support a more aggressive growth rate range of 4.0% to 5.0%. Staff emphasizes that it believes this growth rate is probably higher than what investors expect for the electric utility industry considering that expected long-term nominal GDP growth is approximately 4.5%. For this reason, Staff places primary weight on its multi-stage DCF analysis.

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[19] 2003 Mergent *Public Utility & Transportation Manual*, p. a15-a18.

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

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 4.5% and a growth rate range of 4.0% to 5.0% -- Staff has estimated the proxy group cost of common equity to be 8.5% to 9.5% (*see* Schedule 12).

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[21] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for Empire.

A multi-stage DCF may use either two or three growth stages, depending on the situation being modeled. In either case, the last stage must use a sustainable rate as it is considered to last into perpetuity. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate estimate for the final stage because this rate is assumed to last in perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[22]

In the present case, Staff used a three-stage DCF approach, the stages being years 1-5, years 6-10, and years 11 to infinity.[23] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 13-1 through 13-3). Based on this set of assumptions, Staff's initial findings using a multi-stage DCF analysis is an estimated cost of

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

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

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

common equity for the proxy group in the range of 8.40% to 9.13%, midpoint of 8.77%. Because the average credit rating of the comparable companies is 'BBB+' and the credit rating of Empire is 'BBB-', Staff increased the approximate midpoint ROE estimate by 35 basis points to reflect the higher risk implied by this credit rating differential. The spreads between 'BBB+'-rated utility bonds and 'BBB-'-rated utility bonds has averaged approximately 35 basis points during the period November 2010 through January 2011.[24] Therefore, Staff recommends a return on common equity in the range of 8.60 percent to 9.60 percent based on an adjusted midpoint of approximately 9.10 percent.

ii Stage one

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analysis should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

iii. Stage two

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

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[24] Staff used bond yield data from BondsOnline.com pursuant to a subscription agreement Staff has with BondsOnline.

iv. Stage three

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

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

v. Electric Utility Industry Long-term Growth Rates

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

In testimony in the current Kansas City Power & Light Company ("KCPL") and KCPL-GMO ("GMO") rate cases, File Nos. ER-2010-0355 and ER-2010-0356, respectively, Staff provided historical electric utility growth information published in the 2003 Mergent *Public Utility and Transportation Manual* to show that a long-term electric utility growth rate shouldn't be any higher than 3% to 4%. However, in responding to concerns raised by KCPL's and GMO's ROR witness about this data in those cases, Staff was not able to replicate the Mergent data. Consequently, Staff decided to perform its own study of long-term growth in per share data for a proxy group of electric companies (*see* Schedules 14-1 through 14-4).

The Financial Analysis Department has access to Value Line data on *Central* region electric utility companies dating back to 1968.[25] Although Staff has access to current electric

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

utility financial data for all regions of the United States (*Central, East* and *West*), Staff's access to older data from the *East* and *West* regions is limited. Staff believes it is important to analyze electric utility industry financial data to at least the early 1970s since this was approximately the beginning of the last large construction cycle for the electric utility industry.[26] Because 1968 is consistent with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated energy merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc. bankruptcy in December 2001. Considering that much of this disruption was caused by deregulation, Staff does not consider the information during this period to be informative for understanding investors' growth expectations for regulated electric utility operations.

Staff did not apply rigid selection criteria for purposes of selecting *Central* region electric utility companies contained in Edition 5 of the Value Line Investment Survey. However, Staff did eliminate companies that generally did not have at least 70% of revenues from electric utility operations in the late 1990s. Staff also eliminated companies that appeared to be impacted significantly by restructuring in anticipation of the restructuring of the electric utility markets in the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major mergers, acquisitions and/or restructurings. Staff only included companies in which comparable data was available for each year of the period 1968 through 1999. The companies Staff selected are shown in Appendix 2, Schedules 14-1 through 14-4.

Staff's analysis of these electric utility companies' data over the last electric utility construction cycle indicates that average long-term growth slowly increased through the late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on Staff's calculation of a simple average of all of the companies' growth rates over this period. Because a simple average gives each company equal weight, Staff believes this approach is

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

appropriate because it does not introduce possible size bias. As can be seen in the attached Schedules, the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth rate was 3.18% and the overall average for DPS, EPS, and BVPS was 3.59%.

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

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

vi. Perpetual Growth Rates Used in Investment Analysis

Goldman Sachs generally assumes a perpetual growth rate of 2.5% when performing a DCF analysis of regulated electric utility companies (*see* Appendix 2, Attachment E).[27] If Staff had assumed a perpetual growth rate of approximately 2.5% in its multi-stage DCF analysis, Staff's estimated cost of equity would have been approximately 8.04% for the proxy group.

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

[27] Michael Lapides, Zac Hurst, Jadieep Malik and Neil Mehta, *United States: Utilities: Power – Electric Utilities*, "Powering On: Tilting to commodity oriented utilities and IPPs," September 29, 2009, p. 20.

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

vii. Commission Preference for GDP Growth

Finally, although Staff does not believe the use of long-term GDP growth is an appropriate proxy for the perpetual growth rate for electric utilities, Staff does recognize that the Commission indicated a preference for this approach in its *Report and Order* in Case No. ER-2010-0036. In its *Report and Order* the Commission stated a preference to use historical GDP growth from 1929 through 2008 to derive an expected growth rate of 6.0% for the economy. Although Staff does not recommend the Commission use GDP as a proxy for perpetual growth in this case, if the Commission should choose to do so, Staff advises the Commission to use growth rates that are consistent with long-term projections for GDP growth in the current economic environment. This growth rate would be approximately 4.5% based on various projections available. If Staff makes this assumption in its multi-stage DCF analysis, then the estimated cost of equity is approximately 9.50% for the proxy group. After applying Staff's proposed adjustment of 35 basis points to consider Empire's lower credit rating, the cost of equity estimate would be approximately 9.85%.

G. Tests of Reasonableness

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

1. The CAPM

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

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

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

For inputs, Staff relied on historical capital market return information through January 2011. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending January 31, 2011; that figure was 4.38%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 16). The average beta ("β") for the proxy group was 0.66. For the market risk premium ("Rm – Rf"), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.[28] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2009, which was 6.00%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2009, which was 4.40%.

Staff's CAPM is presented on Schedule 16. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 8.31% and 7.26%, respectively. These low cost of common equity results support the reasonableness of Staff's higher cost of equity estimates from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 7% to 8% range for utility stocks.

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

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity ("YTM") of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4% range.[29] Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% is appropriate. This is especially true considering that regulated utility stocks behave like bonds. For the months of November and December 2010 and January 2011, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 5.49% and 6.07% respectively.[30] Adding a 3% risk premium, the "rule of thumb" predicts a cost of common equity between 8.49% and 9.07%. Adding a 4% risk premium, the "rule of thumb" predicts a cost of common equity between 9.49% and 10.07%.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using the average authorized returns published by Regulatory Research Associates ("RRA") as a benchmark. According to RRA, (*see* Appendix 2, Attachment F), the average authorized cost of common equity for electric utility companies for electric companies for the year 2010 was 10.34% based on 59 total decisions (first quarter – 10.66% based on seventeen decisions; second quarter – 10.08% based on fourteen decisions; third quarter – 10.26% based on eleven decisions; fourth quarter – 10.30% based on seventeen decisions). The average authorized cost of common equity for electric utility companies for 2009 was 10.48% based on 39 total decisions (first quarter – 10.29% based on nine decisions; second quarter – 10.55% based on ten decisions; third quarter – 10.46% based on three decisions; fourth quarter – 10.54% based on seventeen decisions).

The average authorized ROR for electric utilities for 2010 was 7.99% based on 59 total decisions (first quarter – 7.95% based on seventeen decisions; second quarter – 7.95% based on fifteen decisions; third quarter – 8.16 based on twelve decisions; fourth quarter – 7.95% based on

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

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

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

While Staff's recommended ROE for Empire is below the average authorized returns published by RRA, Staff's high end recommended ROR is close to the average authorized RORs published by RRA.

H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover Empire's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for Empire in the range of 7.46% to 7.96% (*see* Schedule 17). This rate was calculated by applying an embedded cost of long-term debt of 6.36% and a cost of common equity range of 8.60% to 9.60% to a capital structure consisting of 49.36% common equity and 50.64% long-term debt. Staff urges the Commission to accept its recommendation and in order to allow Empire to earn a fair return on its net rate base.

Staff Expert/Witness: Shana Atkinson

VI. Rate Base

A. Plant In Service and Depreciation Reserve

1. Plant in Service as of November 30, 2010

Accounting Schedule 3, Plant in Service, reflects the rate base value of Empire's plant in service at November 30, 2010, by account.

Staff Expert/Witness: Amanda C. McMellen

2. Iatan 1 Adjustments

The Staff has proposed various disallowances concerning the construction costs incurred on the Iatan AQCS project. These disallowances are discussed in more detail in the Construction Audit and Prudence Review Report.

Staff Expert/Witness: Charles R. Hyneman

3. Iatan 2 Adjustments

The Staff has proposed various disallowances concerning the construction costs incurred on this projects. These disallowances are discussed in more detail in the Construction Audit and Prudence Review Report.

Staff Expert/Witness: Charles R. Hyneman

4. Plum Point Adjustments

The Staff has proposed a disallowance concerning the construction costs incurred on this project. This disallowance is discussed in more detail in the Plum Point construction audit report.

Staff Expert/Witness: Charles R. Hyneman

5. Plant Adjustments: Allocation to Gas

Empire records its general plant in service balances entirely on its electric books. The Staff adjusted Empire's plant balances to allocate a portion of the Company's general plant to Empire's natural gas business for rate case purposes.

Staff Expert/Witness: Amanda C. McMellen

6. Depreciation Reserve as of November 30, 2010

Accounting Schedule 4, Depreciation Reserve, reflects the rate base value of Empire's depreciation reserve at November 30, 2010, by account.

Staff Expert/Witness: Amanda C. McMellen

7. Reserve Adjustments: Allocation to Gas

Empire records its depreciation reserve associated with general plant entirely on its electric books. The Staff allocated a portion of the general plant depreciation reserve to Empire's natural gas business for rate case purposes.

Staff Expert/Witness: Amanda C. McMellen

8. Reserve Adjustments: Other

Adjustments were made to the appropriate reserve accounts based on the disallowances made regarding the Iatan 1 AQCS, construction of Iatan 2, Iatan common plant, and construction of Plum Point. In addition, the Staff is proposing adjustments to state the Iatan 1 AQCS, Iatan 2 generating unit, Iatan common plant, and Plum Point generating unit reserves at an October 31, 2010 level.

Staff Expert/Witness: Amanda C. McMellen

9. Plant & Depreciation Reserve Adjustments: Capitalized Incentive Compensation

During the test year and update periods, Empire capitalized a portion of its incentive compensation for the Employee Stock Purchase Plan and the Bonus Incentive Plan ("Lightning Bolts"). The Staff made adjustments to the plant in service in the amount of ($234,956) and depreciation reserve in the amount of ($6,141) in order to eliminate these amounts from cost of service. Since the Staff removed these non-cash compensation expenses from its cost of service income statement (*see* Section VIII. F. 4. c.), the Staff is also making an adjustment to remove these costs from rate base in this case.

Staff Expert/Witness: Amanda C. McMellen

B. Cash Working Capital (CWC)

The cash working capital requirements for the Company in its rate base have been updated from the previous rate case, No. ER-2010-0310. Staff is using the same revenue and expense lags that were agreed to by the Company and Staff in File No. ER-2010-0130, but has updated the adjusted test year amounts associated with each CWC accounting schedule line item.

Staff Expert/Witness: 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 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 November 2010.

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, except for the Plum Point and Iatan materials and supplies account. These accounts showed a steady trend upwards and Staff felt that using the last known balance for these two particular accounts was more appropriate than the 13 month average. 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 electric rate base in this proceeding.

Staff Expert/Witness: Casey Westhues

D. Fuel Inventories

Coal Inventory - Staff used the results of its fuel model to calculate the annual amount of coal used by each Empire generating plant to meet its total company normalized native load. Empire 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 its regulated retail electric customers. To determine the amount of coal inventory, the average daily burn by unit must be calculated. The average daily burn by unit is derived by dividing the annualized tons burned by the difference between 365 days and the number of annual planned outage days. Then, the average daily burn is multiplied by an appropriate number of days of inventory for each plant resulting in a burn inventory. 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 by Empire 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 both at Kansas City Power & Light Company's (KCPL) Iatan Generating Stations, of which Empire is a 12% owner of Iatan 1 and 2; and Plum Point Energy Associates, LLC's Plum Point Energy Station, of which Empire is a 7.52% owner.

Staff then added an estimated level of basemat coal to the burn inventory for each unit except for Plum Point, for which basemat coal is capitalized. Basemat coal is the bottom portion of a coal pile that is not usable as fuel due to contamination by soil, clay, and other contaminants. Staff multiplied the resulting total tonnage of inventory for each unit by Staff's proposed delivered cost of coal per ton for that unit. This dollar amount was multiplied by 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.

This is the first Empire rate case in which Staff is including basemat coal in Staff's recommended coal inventory costs. Staff recommends that the cost associated with basemat established in this case should be the cost representing basemat in subsequent Empire rate cases without adjustment for changes in coal prices, unless the Company can demonstrate through engineering studies or other means that the amount of basemat coal has materially changed from that used in prior rate proceedings.

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

Staff Expert/Witness: Keith D. Foster

E. 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/Witness: Amanda C. McMellen

F. Customer Demand Programs Regulatory Asset

As part of Empire's Experimental Regulatory Plan approved in Case No. EO-2005-0263, Empire's Customer Programs Collaborative (CPC) was ordered to include Staff, Public Counsel, Department of Natural Resources and other interested parties to advise Empire on the development, implementation, monitoring and evaluation of demand response, energy efficiency and affordability programs for Empire's Missouri customers. Also, as a result of the *Stipulation and Agreement*, the CPC retained a consultant to evaluate the Demand Side Management (DSM) and affordability programs.

The DSM Regulatory Asset Account 182318 contains costs that have been incurred for ten (10) DSM programs[31] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program and (2) DSM market research costs. Based on Staff's participation in the CPC and Staff's review of the costs in Account 182318, Staff has no recommended disallowances to the levels of costs contained in Empire's DSM Regulatory Asset Account. All unamortized actual costs associated with the CPC and new DSM programs are to be included in rate base as a regulatory asset, per the EO-2005-0263 *Stipulation and Agreement*. The Staff is using the November 30, 2010 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. H. 7).

Staff Experts/Witnesses: Amanda C. McMellen and Hojong Kang

G. Amortization of Electric Plant

The Staff has adjusted the amortization reserve for electric plant intangible assets to reflect the updated balances through November 30, 2010. The amortization reserve balance as of November 30, 2010 is $8,168,792 and was included as an offset to rate base in the Staff's Accounting Schedules.

Staff Expert/Witness: Amanda C. McMellen

[31] DSM programs consist of demand response, energy efficiency and affordability programs, including the Low Income Weatherization programs and Interruptible Service Rider (IR).

H. Customer Deposits

The amount of customer deposits shown on Accounting Schedule 2, Rate Base, represents a 13-month average (November 2009 – November 2010) 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 ongoing level of $8,035,398 as an offset to rate base.

Interest on customer deposits is also included 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 current filed Tariff. The Tariff (Section 3, Page 5) states that the "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, $320,741, is included in Staff Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert/Witness: Casey Westhues

I. 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 November 30, 2010, the end of the Staff's update period in this case, is shown on Accounting Schedule 2, Rate Base.

Staff Expert/Witness: Casey Westhues

J. Accumulated Deferred Income Taxes (ADIT)

Empire's ADIT represents, in effect, a net 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 ADIT accounts reserve represents a source of cost-free funds to Empire. Therefore, Empire's rate base is reduced by the ADIT 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 ADIT 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, Deferred Federal Tax Asset-Miscellaneous, Deferred Tax Liability-Iatan Deferred Charges, Deferred Tax-ITC Tax Basis-Iatan, Contributions in Aid of Construction, Post-retirement Benefits – Pensions, and Capitalized Interest.

The Staff's proposed disallowances to the costs of the Iatan 1 AQCS, the Iatan 2 unit, Iatan common plant and the Plum Point unit will have an impact on the balances included in Staff's case for accumulated deferred income taxes. The Staff has adjusted Empire's ADIT with an estimate of the impact of its proposed disallowances associated with those projects. When the Staff obtains a more accurate quantification of this impact from the Company, it will revise its ADIT adjustment amount.

Staff Expert/Witness: Paul R. Harrison

K. Vegetation Management Tracker

In File 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) and infrastructure inspection costs compared to the rate allowance granted for this item by the Commission of $8,575,000 (Missouri Jurisdictional) in the 2008 rate case. In the

Non-Unanimous Stipulation and Agreement filed May 12, 2010, in Empire's last rate case, File No. ER-2010-0130, Staff and the Company agreed to continue the vegetation tracker, but terminated the infrastructure tracker approved in File No. ER-2008-0093. The Non-Unanimous *Stipulation and Agreement* stated on page 6:

> A. The vegetation tracker established in Empire's last electric rate case, Case No. ER-2008-0093, and trued-up through December of 2009 in the Staff Accounting Schedules in this case, will continue. The vegetation tracker will be rebased in Empire's Rate Filing called for in Section III.D.7. of the *Empire Experimental Regulatory Plan Stipulation* (the Iatan 2 case), and evaluated for termination in Empire's electric rate case following Empire's Rate Filing called for in Section III.D.7. of the *Empire Experimental Regulatory Plan Stipulation*. The base for the vegetation tracker in this case, Case No. ER-2010-0130, will be set at $9 million, with a $13 million cap and a $7 million floor (all Missouri jurisdictional amounts).
>
> B. Empire's current infrastructure tracker will terminate on the effective date of the revised tariff sheets approved in this case

The remaining unamortized balance of the vegetation and infrastructure tracker set up in File No. ER-2008-0093 as of November 30, 2010 is $1,462,569. The tracker amount for this case is $988,944, calculated as the difference between Empire's rate recovery of vegetation management costs from January 1, 2010 to November 30, 2010, and infrastructure inspection costs from January 1, 2010 to September 9, 2010, and Empire's actual expenditures for these functions for these time periods. The Staff has included these amounts in its rate base. There is also an adjustment in the Income Statement to amortize the Commission Rules Tracker balances to expense over a five year period (*see* Section VIII. H.2).

Staff Expert/Witness: Paul R. Harrison

L. Carrying Costs

<u>1. Iatan 1</u>

Pursuant to Empire's regulatory plan approved in Case No. EO-2005-0263, Empire has deferred certain "carrying costs" associated with the Iatan 1 AQCS investment past its in-service date into Account 182.308, Iatan Deferred Carrying Costs. (Deferral of carrying costs after a project's in-service date is also known as "construction accounting.") In its last case, File No.

ER-2010-0130, the Iatan 1 AQCS project was included in Empire's rate base as of December 31, 2009, but a prudence review of these costs was delayed until the Company's next rate case. Also, in File No. ER-2010-0130, Empire was granted rate recovery of an amortization of Iatan 1 AQCS deferred carrying costs.

Based on the results of its Construction Audit and Prudence Review for the Iatan Project, Staff recommends disallowance of certain costs from Empire's Iatan 1 plant balances. These disallowances are described in the Iatan 1 and 2 construction audit report. The effect of these disallowances, if accepted by the Commission, would be to reduce the balance of the Iatan 1 AQCS plant balance below the balance for this project previously included in Empire's rates in File No. ER-2010-0130. These disallowances had the impact of removing from Empire's Iatan 1 plant balances all costs that would have been included in the carrying costs calculation in this rate proceeding[32]. Therefore, Staff did not include an amortization of these costs in expense or increase Staff's rate base calculation to reflect the addition of carrying costs for Iatan 1.

Staff Expert/Witness Amanda C. McMellen

2. Iatan 2

Pursuant to Empire's regulatory plan approved by the Commission in File No. EO-2005-0263, Empire has deferred certain "carrying costs" associated with the Iatan 2 generating unit investment past its in-service date into Account 182.332, <u>MO IatanII Df Chg ER-2010-0130</u>. Based on the results of its Construction Audit and Prudence Review for the Iatan project, Staff recommends disallowance of certain costs from Empire's Iatan 2 plant balances. These disallowances are described in Section VI.A.3. The Staff has removed any construction accounting allowances associated with Iatan 2 disallowances from its rate base and expense amortization calculations. The construction accounting amounts allowed by the Staff in this proceeding include allowances for depreciation expense, and debt and equity-derived carrying charges. The balance of Iatan 2 carrying costs was reduced by Empire's deferral of fuel and purchased power expense savings it has incurred due to the addition of Iatan 2 to its generating system from the unit's in-service date through November 30, 2010.

Staff Expert/Witness Amanda C. McMellen

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[32] Pursuant to *Stipulation and Agreement* filed on February 25, 2010 in File No. ER-2010-0130, any amounts previously included in rate base and that the Commission finds to have been imprudently incurred are subject to customer bill credits.

3. Plum Point

Pursuant to Commission approval of the *Non-Unanimous Stipulation and Agreement and Joint Proposal Regarding Certain Procedural Matters* dated February 25, 2010, in File No. ER-2010-0130, Empire has deferred certain "carrying costs" associated with the Plum Point generating unit investment past its in-service date into Account 182.331, MO PlumPt Df Chgs ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for Plum Point, Staff has recommended one disallowance to Empire's Plum Point plant balances. In accordance with the terms of the February 25, 2010, *Non-Unanimous Stipulation and Agreement,* the Staff has not calculated any carrying costs for the Plum Point unit from its in-service date (August 13, 2010) to the day before the effective date of rates in Empire's last rate proceeding, File No. ER-2010-0103 (September 9, 2010). The Staff included in its rate base the allowable balance of this deferred asset as of November 30, 2010.

Staff Expert/Witness: Amanda C. McMellen

M. Regulatory Plan Additional Amortization - Rate Base

This amount is the balance of Empire's accumulated regulatory plan amortizations previously collected in customer rates through November 30, 2010. Regulatory plan amortizations are discussed in more detail in Section IX of this Report.

Staff Expert/Witness: Mark L. Oligschlaeger

N. SWPA Hydro Reimbursement Payment

On September 16, 2010, Empire received a payment in the amount of $26,563,700 from the Southwestern Power Administration (SWPA), to compensate Empire for the expected financial impact of a future reduction in capacity at its Ozark Beach hydroelectric plant. The reduction in capacity at Ozark Beach is due to the Energy and Water Development Act of 2006, federal legislation which requires a decrease in available head waters at Ozark Beach. The payment received from the SWPA was based upon an estimated 50 years of remaining life for the Ozark Beach facilities, with an assumed starting curtailment date for capacity in 2013.[33]

[33] Empire has since projected the curtailment will not begin until 2016, though the Ozark Beach plant manager has stated to the Staff that the plant should remain in operation 50 years beyond that date as well.

Empire has also informed the Staff that the IRS will likely consider the payment to be fully taxable as income in 2010. Per Empire's Third Quarter Securities and Exchange Commission Form 10-Q (p. 33), the Company has recognized a current income tax liability related to the SWPA payment.

The approximate $26.6 million payment is a prepayment from the federal government to Empire for future economic damages related to reduced hydroelectric capacity at Ozark Beach. Empire has stated that it intends to flow back this payment to customers in the future over an appropriate period of time. Accordingly, the Staff recommends that the SWPA payment be included in Empire's rate base as an offset in this case. The Staff does not believe that any amortization of this amount as a reduction to expense is appropriate until such time as the capacity restrictions go into effect at Ozark Beach. Given its taxable status, the Staff is treating this payment as a tax timing difference in its income tax accounting schedule to recognize that taxes are currently due to the federal and state governments regarding this payment, but that this amount will not be reflected on Empire's income statement until later periods. However, in recognition that receipt of this payment from the SWPA is a one-time event, the Staff is proposing to spread the tax effect of this payment over a three-year period. Reflecting a portion of the tax effect of this item in Empire's rates will create a deferred tax asset on Empire's balance sheet.

Staff Expert/Witness: Mark L. Oligschlaeger

VII. Allocations

A. Jurisdictional Allocations

The Staff has used the same jurisdictional allocation factors in this proceeding as they did in Empire's last case, No. ER-2010-0130.

Staff Expert/Witness: Mark L. Oligschlaeger

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 using an appropriate unit of measurement, or allocated through use of a general factor. The Staff is proposing to use the same corporate allocation factors, in effect as of January 1, 2010, as it used in Empire's last rate case.

Staff Expert/Witness: Amanda C. McMellen

VIII. Income Statement

A. Rate Revenues

1. Introduction

As the largest component of Empire's operating revenues result from rates charged to 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 Missouri retail customer electric rate 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 also 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/Witness: Amanda C. McMellen

2. Definitions

Operating Revenues: Revenue 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 profit 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 continue to be eliminated from consideration in general rate proceedings, and instead be handled entirely through Empire's Fuel Adjustment Clause mechanism, as was done in Empire's last rate proceeding.

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/Witness: Amanda C. McMellen

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 class. 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/Witness: Amanda C. McMellen

4. Regulatory Adjustments to Test Period Usage and Rate Revenue

a. Development of Weather Normalization Factors

Electric usage for certain classes of service 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, certain classes of service of Empire's electric load are 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 Dr. Seoung Joun Won's discussion of annualizations in subsection g, Large Power Customers, Praxair and Non-Missouri Large Power Customer Annualizations for additional information on this topic.

Staff modeled each weather sensitive class' weather response function using two-day weighted mean temperatures, the hourly load research sample, and binary variables to model the impact of the day of the week, month of the year, and holidays in a multivariate regression analysis using the MetrixND® software package on a calendar month basis. The resulting weather response functions were then simulated using normal two-day weighted mean temperatures to produce weather normalized usage on a calendar month basis. Staff witness Dr. Seoung Joun Won provided the actual two-day weighted mean and the normal two-day weighted mean daily temperatures that were used in the analysis.

Staff analyzed Empire's billed usage data to determine usage on a revenue month basis and proportion of usage attributable to each billing cycle. Staff removed oil-pipeline-company customer's billed usage data the billing data prior to the determination of the cycle weights due to the randomness of these customers' usages. The kWh usage of these customers was subsequently included in the determination the 365-Days Adjustment to revenue month usage.

Staff Expert/Witness: 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. Due to the unique manner in which this case was filed, Staff's adjustments to Usage and Revenue are based on a test period of July 2009 - June 2010.[34]

Staff selected Springfield, Missouri weather station to develop "normal" average temperatures with which to compare the test period temperature. To recognize recent weather trends, the time period used in determining the normal values of weather variables is the 30-year period (January 1, 1979 - December 31, 2008) as used by Company and accepted by Staff in Empire's last rate case, File No. ER-2010-0130. For checking consistency of weather data through the 30-year period, a double-mass curve analysis was employed. According to the result of analysis, there is no data inconsistency through the 30-year period.

NOAA[35] states that "climate normal is defined, by convention, as the arithmetic mean of a Climatological 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, File No. ER-2010-0130, to calculate the daily normal weather temperature

[34] The test year selected for this case, File No. ER-2011-0004, is the twelve months ending June 30, 2009, and is the same test year used in the prior Empire case, File No. ER-2010-0130. Staff used a more recent test period for purposes of certain normalization and annualization adjustments.

[35] National Oceanic and Atmospheric Administration

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.

Because actual temperatures do not smoothly move up and down during the year,[36] these normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test period.

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

Staff Expert/Witness: Seoung Joun Won, PhD

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, Staff calculated the weather adjustment to rate revenues 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

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[36] 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.

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/Witness: Seoung Joun Won, PhD

d. Annualization for Rate Change

Test period rate revenues do not reflect the rate changes implemented on September 10, 2010, as a result of File No. ER-2010-0130. Thus test period 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 period. Staff's method of computing annualized revenues for each rate class was to multiply test period billing units by current rates. The difference between these revenues and those billed during the test period under the prior rates provided the amount of the adjustment.

Staff Experts/Witnesses:
Large Power, Praxair, and other Non-weather-sensitive classes: *Curt Wells*
Weather-sensitive classes: Seoung Joun Won, PhD

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 allocated to the test period 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 period and 365 days gives us the days adjustment.

Staff Experts/Witnesses:
Large Power MO and Non MO usage and revenue: *Curt Wells*
for all other classes: Walt Cecil(usage) and Seoung Joun Won, PhD (revenue)

f. 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 (November 30, 2010) had existed throughout the entire test year ending June 30, 2099. 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 g. 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 as of November 30, 2010.

Staff Expert/Witness: Amanda C. McMellen

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

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

The adjustments are for the test period of July 1, 2009 – June 30, 2010, updated for known and measurable changes through November 30, 2010. There were 38 customers in the MO LP rate class during the test year. A data check was done for billing corrections prior to making adjustments.

Because each Large Power customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor, class sales and revenues were annualized on an individual customer (account) basis. Each customer's individual monthly demand and energy use, measured over multiple years prior to the test period, the 12 months of the test period, and the five-month update period, were examined graphically to determine whether an adjustment was needed.

Out of the 38 Missouri LP customers, twelve LP customers' loads were adjusted; no customer entered or left the LP class. The load adjustments updated the monthly usage to reflect the latest available 12-months of usage.

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

Staff Expert/Witness: Curt Wells

h. Special Contract Revenue Imputation

The special treatment of the interruptible credits associated with Praxair's contract stipulated in Case No. ER-2001-299 is continues effective through the test year and update period; however, revenues were imputed as if the contract did not exist to prevent harm to other ratepayers.

Staff Expert/Witness: Curt Wells

i. Non-Missouri Adjustments

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 growth. A "days" adjustment to Usage and two customer load annualizations were done for Non-Missouri Large Power customers. Non-Missouri usage was adjusted to provide normalized kWh to Staff witness Walt Cecil for inclusion in Net System Input.

Staff Expert/Witness: Curt Wells

j. Rate Switching

During the test period, 97 customers changed rate classes. Forty nine moved between the CB and GP classes, 14 moved between SH and TEB, 10 moved between CB to SH, three moved between TEB to GP, 18 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 slightly increase 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 period were then re-priced based on their final rate code and their revenues were added to the final rate code.

Staff Expert/Witness: Seoung Joun Won, PhD

k. Annualization of Excess Facility Charge Revenues

These revenues result from charges to customers for facilities provided in excess of those normally made available. These revenues are annualized for changes during the test period 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/Witness: Curt Wells

l. 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/Witness: Curt Wells

B. Off-System Sales and Transmission Revenue

1. Transmission Revenue

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 the years ending November 30, 2008 through November 30, 2010. The test year and update period margins from transmission transactions were negative for Empire, which means Empire paid more to other transmission-owning utilities for transmission service than Empire received from other utilities for transmission service. Staff believes use of a three-year average in this case produces a normalized level of transmission margin. The Staff adjustment decreases test year transmission transaction margins to a total of negative $259,665.

Staff Expert/Witness: 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 negative $139,900. This adjustment reflects an ongoing level of the gain on the sale of SO2 allowances included in revenues by Empire for the twelve months ended November 30, 2010. Changes over time in the amount of revenues Empire receives from SO2 allowances are currently reflected in its Fuel Adjustment Clause calculations and the Staff recommends that this treatment continue.

Staff Expert/Witness: Keith D. Foster

D. Fuel and Purchased Power

Staff's adjustments to annualize and normalize Empire's fuel expense are reflected in Accounting Schedule 10, Adjustments to Income Statement.

Staff Expert/Witness: 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 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/Witness: 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 and trucking charges. Staff annualized the natural gas transportation expense based on Empire's contractual obligations with Southern Star on January 1, 2010. In regard to trucking costs, all PRB (western) coal destined to the Riverton units is delivered by rail to Asbury, and then hauled by Asbell Trucking to the Riverton plant. A 12-month average (December 1, 2009 to November 30, 2010) trucking charge of $3.6376 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/Witness: Keith D. Foster

b. Purchased Power – Capacity Charges

Capacity charges represent fixed amounts Empire pays for reserving 50 MW capacity from Plum Point. Effective September 1, 2010, Empire contracts for this power with Plum Point Energy Associates, LLC and pays a fixed component and an energy component. Generally, there is also an amount for Plum Point operation and maintenance costs included within the energy charge. 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 are intended to cover part of the fixed expenses of operating a generating facility.

Staff's adjustment to purchased power expense in this case annualizes demand charges for Empire's Plum Point Purchase Power Agreement.

Staff Expert/Witness: Keith D. Foster

2. Variable Costs

The Staff estimates the total company variable fuel and purchased power expense for Empire for the twelve months ending June 30, 2010, to be $139,967,927.

The Staff used the RealTime™ 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 to determine 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. The hourly net system was provided by Staff witness Walter Cecil.

Staff Expert/Witness: Shawn E. Lange

a. Fuel Prices

Staff computed its level of fuel expense using prices and quantities contracted by Empire for delivery through the end of the test year update period (November 30, 2010), including prices and quantities agreed to in fuel contracts that became effective as of January 1, 2010 and for freight contracts that became effective after June 30, 2010. These fuel prices included prices for coal, natural gas, and oil, as well as associated transportation charges.

Staff Expert/Witness: Keith D. Foster

i. Coal Prices

Staff determined its coal price by generation facility based on a review and analysis of Empire's current coal purchase and coal transportation contracts. Staff's proposed coal prices reflect Empire's actual contracted coal purchase prices in effect at January 1, 2010 and transportation prices in effect after June 30, 2010. For the Iatan 2 and Plum Point units, Staff's proposed coal prices reflect the actual contracted coal purchase and transportation prices in effect at the time the plants became operational in 2010.

Staff Expert/Witness: Keith D. Foster

ii. Natural Gas Prices

The natural gas price used in this case by Staff of $5.65 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 the twelve months ending November 30, 2010. The weighted average price for the non-hedged component is $4.546 per MMBtu. The hedged component of natural gas costs was calculated by applying a weighted average for the actual hedged purchases contracted for at November 30, 2010, that are applicable to Empire's forecasted gas needs for the twelve months ending November 30, 2011. The weighted average price for the hedged component is $5.819 per MMBtu. Staff weighted the hedged gas price at 87% of its overall gas price recommendation, as Empire has contracted to meet approximately 87% of its projected natural gas usage through November 30, 2011 with hedged gas supplies. Empire's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Keith D. Foster

iii. Fuel Oil Prices

Staff used a weighted average price of 1,618.71 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 $2.256482; and (4) converting this per gallon price into the cents per MMBtu, 1,618.71. 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.

Staff Expert/Witness: Keith D. Foster

3. Spot Market Prices/Energy Availability

Spot market purchases are purchases of energy made by a utility on an hourly basis rather than through a longer-term contract. A utility decides to buy spot energy from one or more suppliers based on the economic environment and the availability of its generating units and capacity purchases. Purchases of spot energy are made in order to lower overall generation costs when the spot market price is below both the marginal cost of providing that energy from the company's generating units and the utility's firm capacity purchases.

Staff used in this case a procedure developed by the Engineering Section of the Commission's Energy Department in 1996 that is described in "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market," (March 18, 1996). The method uses a statistical calculation based on the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.

The price inputs for the calculation are actual hourly non-contract transaction prices in the twelve month period ending June 30, 2010. These were obtained from data the Company supplied to comply with 4 CSR 240-3.190 (3.190 data). The Staff's methodology yields a spot energy price for each hour of the year. This data set containing 8760 hourly spot energy prices is then used as one of the inputs to the Staff's REALTIME fuel model.

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, 2010, obtained from the data Empire supplied to comply with 4 CSR 240-3.190, by finding each months, hourly maximum purchase demand.

Staff Experts/Witnesses: Erin L. 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 its own internal needs, and excludes 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 load data used in the analysis of the test year were submitted by Empire in compliance with the Commission's rule 4 CSR 240-3.190. Data submitted by Empire in response to Data Request No. 132 were found to be inconsistent with the data provided under 4 CSR 240-3.190 and after review by Staff and the Company, Empire informed the Staff that the response to DR 132 was erroneous and that the data supplied in compliance with 4 CSR 240-3.190 should be used in Staff's analysis.

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 net system usage (usage) are considered independently, but with the same methodology because usage responds differently to weather than do peak loads.

Usage is calculated as the sum of each day's observed hourly NSI. The peak demand is the maximum hourly usage for the day. Separate regression models, one for daily usage and one for daily peak demand are used to determine the weather adjustment for each day. Staff witness Dr. Seoung Joun Won of the Energy Department provided actual and normal daily temperatures used to weather normalize NSI[37].

NSI is the sum of retail, wholesale and company usages together with losses in the transmission and distribution system. In order for the normalized NSI to be consistent with the normalized, annualized kWh used to determine normalized, annualized revenue, 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[38], and company usage as provided by Empire in compliance with 4 CSR 240-3.190, were summed and adjusted for line losses by an average annual loss 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.

[37] 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.

[38] Weather normalized wholesale usage determined using the same process used to weather normal NSI

Once completed, the test-year hourly normalized, annualized NSI 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 Expert/Witness: 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.

Staff Expert/Witness: Walt Cecil

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.) between Empire's generating sources and its customers' meters. In addition, small, fractional amounts of energy that is either diverted (stolen) or unmetered (unmetered usage) 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; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – Total Sales

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

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

NSI is also equal to the sum of the Company's net generation and net interchange. Net interchange is the difference between off-system purchases and 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 and metered continuously. The net of off-system purchases and off system sales (Net Interchange) is also similarly monitored.

Staff calculated the loss percentage of Empire's system, for the twelve months ending June 2010, as 6.89% of NSI. Staff witness Walt Cecil used this loss percentage in the development of hourly loads used in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

5. Planned and Forced Outages

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 nine 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/Witness: Shawn E. Lange

E. Depreciation

1. Depreciation Summary

Staff conducted a depreciation study of Empire's capital assets which included an analysis of the accumulated reserve for depreciation based on plant account balances as of December 31, 2009. Based on its study, Staff has calculated updated depreciation rates for the Company as indicated in Appendix 3, Schedule JAR(DEP)-1 of this report. However, for the reasons stated in this Report, for all plant accounts other than applicable to the Iatan 2 generating unit, Staff recommends that the Commission retain the depreciation rates that are currently ordered.[39]

Staff has calculated depreciation expense using the plant account balances as of December 31, 2009 and the depreciation rates that resulted from Staff's study would produce an annual depreciation expense of $42,874,324, which is approximately $1,426,961 less than the depreciation expense resulting from currently-ordered depreciation rates applied to

[39] Staff has created composite rates applicable to the production plant accounts using dollar weighted averages of the existing rates.

December 31, 2009 plant balances. However, as a result of this case there will be a significant increase in total depreciation expense due to the increase in Empire's plant, primarily associated with the new Iatan 2 and Plum Point generating units, regardless of what depreciation rates are ordered by the Commission. Taking those plant additions into account, the total depreciation expense resulting from existing rates for all accounts other than Iatan 2 and Staff's remaining life rates for Iatan 2 is approximately 45 million dollars.

For all plant accounts excluding Iatan 2, Staff recommends the Commission retain the depreciation rates that are currently ordered. However, Staff has created composite rates applicable to the production plant accounts using dollar weighted averages of the existing rates, for ease of accounting. These rates were authorized by the Commission for Empire in Case No. ER-2004-0570. Staff recommends the Commission order depreciation rates for Iatan 2 consistent with Staff's recommendation in KCPL's current rate case, File No. ER-2010-0355, as described below. Empire's currently authorized rates, as well as Staff's updated calculated rates, are listed by plant account on Appendix 3, Schedule JAR(DEP)-2. Staff's recommended rates for Iatan 2 are included on Appendix 3, Schedule JAR(DEP)-3.

Schedule JAR(DEP)-4 of Appendix 3 lists, by plant account, the accumulated reserve for depreciation and the theoretical reserve amount that currently exists as of the study date for Empire. Staff's study indicates an over-accrual of the accumulated reserve for depreciation of approximately $72,132,008.

a. Depreciation

"Depreciation" as applied to depreciable utility plant means the loss in service value, not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service, from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

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

b. Depreciation Study

Because Empire operates its separate production sites as a generation fleet, its depreciation and plant accounts are appropriately treated as living accounts. [40] Therefore, with the exception of the Iatan 2 accounts, Staff used the straight line method, broad group-average life procedure, and whole life technique depreciation system for its depreciation study of the Company's capital assets. Staff has consistently used the whole life technique in developing depreciation rates that reflect expected average service lives for all non-Iatan 2 accounts. The whole life technique does not include an adjustment factor to address over- or under-accruals in the accumulated reserve for depreciation. Staff's use of remaining life for the Iatan 2 accounts and their treatment as dying accounts[41] is addressed elsewhere in this depreciation section. Staff does not recommend any amortization of the excess depreciation reserve accrual at this time, but will continue to monitor this balance.

Staff used the following formula to calculate a depreciation rate for each plant account:

$$\textit{Depreciation Rate} = \frac{100\% - \%\ \textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

[40] The FERC-USOA requires the capital assets of the company used in the conduct of its business be accounted for by functional accounts. Assets used for production of the utility good or service in one group of accounts and assets used for distribution of the good or service in another group of accounts, etcetera. When the technology or method used in a functional account becomes obsolete that is known as a dying account. Living accounts represent ongoing accounts.

[41] The FERC-USOA requires the capital assets of the company used in the conduct of its business be accounted for by functional accounts. Assets used for production of the utility good or service in one group of accounts and assets used for distribution of the good or service in another group of accounts, etcetera. When the technology or method used in a functional account becomes obsolete that is known as a dying account. Living accounts represent ongoing accounts.

This is consistent with the depreciation rate formula that appeared in the Report and Order in Empire's previous rate case, No. ER-2004-0570. As shown in the formula, the average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. The Staff recommended/calculated depreciation rates for each plant account are based on the average service life and net salvage percentage determined applicable to each account, as shown in Appendix 3, Schedule JAR(DEP)-5. That determination is addressed in detail below.

c. Average Service Life

For each plant account, the average service life (ASL) is the expected period, in years, of the useful service of each unit of property in that account, (e.g., meters) regardless of when that unit was first put into service (also referred to as its placement date). An account's ASL is developed in four steps. The first step is to review historical mortality data, historical salvage, and cost of removal data. The data is checked for reasonableness, and to determine whether or not sufficient data exists to perform a statistically significant analysis. In addition, Staff reviews the data to determine if retirements recorded in one historical database are also recorded in another historical database.

The second step is to gain familiarity with the Company's facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with Company operations personnel, engineers, accountants, and other depreciation experts. Current developments such as technological changes, environmental regulations, regulatory requirements, or accounting changes can all affect the average service life of property in an account. Different vintages of plant being manufactured from different materials, changes in installation practices, and the development of a life extending maintenance procedure are some examples of factors contributing to changes in average service lives.

The third step is to perform a statistical analysis of the retirement experience of each utility plant account, followed with analysis of the results for reasonableness for the type of plant in question. To evaluate the retirement experience of a Company's plant accounts, Staff uses depreciation software to analyze historical plant data by calculating the ratio of retirements to exposures by age, and solve for the percent surviving by age to develop a survivor curve for an account. Data regarding plant additions in dollars by year, or vintage, and retirements from each vintage, in dollars by year, are necessary for this analysis. The exposures at a given age are the dollars remaining from the various vintages that have lived to that age. The retirement ratio is the dollars retired during an age interval divided by the exposures at the beginning of that interval. The survivor ratio is then calculated by subtracting the retirement ratio from "1". Multiplying each successive survivor ratio by the percent surviving of the previous age will generate a survivor curve. This original survivor curve can then be smoothed and fitted to an empirically developed statistical model known as an Iowa curve.[42] Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. The average service life of an account's original survivor curve is estimated as the area under the selected Iowa curve.

The fourth step is to apply Staff's engineering experience and informed judgment to the aggregate of the first three steps in the process to assign an appropriate ASL for each plant account. Staff recommends the ASLs, by account, that were ordered in Case No. ER-2004-0570 identified in the attached Appendix 3, Schedule JAR(DEP)-5.

As noted earlier the average service life is just one of two factors determining a given depreciation rate.

d. Net Salvage Percentage

The second factor in determining a given depreciation rate is the net salvage percentage. Consideration is given to the future net salvage (including cost of removal) that property in an account may experience. The net salvage equation is expressed as follows:

Net Salvage = Gross Salvage - Cost of Removal

Gross salvage is the recovered market value of retired plant. Cost of removal is the cost associated with the retirement and disposition of plant from service. Negative net salvage occurs when the cost of removal exceeds gross salvage. A negative net salvage is commonly referred to as an expense or net cost of removal. A negative net salvage percentage is commonly referred to as a net cost of removal percentage. Today, many utility accounts experience a net cost of

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[42] The Iowa curves are widely accepted models of the life characteristics of utility property. The system of Iowa curves is a family of 176 types of utility and industrial property. The curves were developed at the Iowa Engineering Experiment Station at what is presently known as Iowa State University. The Iowa curves were first published in 1935 and reconfirmed in 1980. The original survivor curve is mathematically and visually matched with various Iowa curves to determine which has the most appropriate fit, either for a significant portion of the curve or just a specified portion of the curve.

removal; therefore, the net salvage percentage in the depreciation calculation is negative, which results in an increase to overall depreciation expense.

Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage realized by the Company. This is consistent with the Commission's direction for rate treatment of net salvage from its Report and Order for Empire issued in Case No. ER-2004-0570.

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

e. Analysis of Accumulated Reserve for Depreciation

Another analysis performed with a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. This analysis illustrates whether prior depreciation estimates have differed significantly from actual experience. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date, in this case December 31, 2009 to the calculated theoretical reserves produced from Staff's depreciation study.

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

The need for, the magnitude of, and the timing of an adjustment for an over-accrued or under-accrued depreciation reserve for a particular account should be based upon consideration of several factors: the characteristics of the account, the causes of the difference, the year-to-year volatility of the accumulated provision for depreciation, and the magnitude of the imbalance. Future service life cannot be estimated to a degree of certainty that guarantees that the actual life will not be different. In fact, the depreciation estimation process is dynamic and it is possible that the currently determined ASL recommended by Staff will differ from the ASL that occurs.

Based upon the Commission's currently ordered depreciation rates for Empire, the reserve for depreciation is over accrued by $72,132, 008. This amount has continued to increase since Empire's depreciation rates were last set in Case No. ER-2004-0570. As previously mentioned, Staff is not recommending a decrease in depreciation rates in this case. Furthermore, Staff recommends that the current excess reserve be allowed to stand; i.e., that no amortization of the excess reserve amount be ordered at this time. Staff believes its recommendation to continue the currently-ordered rates for all non-Iatan 2 accounts, including the remainder of Empire's steam production generation fleet, as well as not recommending a reduction or return of the depreciation reserve over accrual at this time, is conservative. The impact of possible future environmental regulations on the ASLs of Empire's plant was considered in developing Staff's conservative approach to its depreciation recommendations in this case.

f. Regulatory Plan Amortizations

As discussed in greater detail by Staff witness Mark L. Oligschlaeger, Staff recommends that the accumulated additional amortizations (or "regulatory plan amortizations") be allocated to the Iatan 2 accumulated depreciation reserve accounts. In the October 27, 2006, *Nonunanimous Stipulation And Agreement Regarding Regulatory Plan Amortizations* in File No. ER-2006-0315, it states that "any Regulatory Plan additional amortization that is provided to Empire pursuant to that *Stipulation and Agreement* shall be used as a reduction in rate base for the longer of (a) at least ten (10) years following the effective date of the August 2, 2005, *Order Approving Stipulation and Agreement* in Case No. EO-2005-0263 or (b) until the investment in plant in service accounts to which the Regulatory Plan additional amortizations are ultimately assigned by the Commission is retired." Staff's recommended treatment for the accumulated additional amortizations is intended to use this amount as a reduction in rate base for the entire life of Iatan 2. Both Staff and Empire expect Iatan 2 to remain in service past August 2, 2015, which is ten years after the effective date of the August 2, 2005, *Order Approving Stipulation and*

Agreement in Case No. EO-2005-0263. The accounting required to perform the assignment to the reserve accounts is described in more detail below.

To calculate applicable depreciation rates, Staff recommends segregating the Iatan 2 steam plant accounts as separate sub accounts from the remainder of the steam generation production fleet[43] accounts. Staff's recommended depreciation rates shown in attached Appendix 3, Schedule JAR(DEP)-3 for Iatan 2 have been adjusted to account for these additional reserves over a life span selected for depreciation purposes. Depreciation rates for the Iatan 2 generating unit only are calculated on a remaining life basis to ensure that ordered rates reflect the benefit of the accumulated additional amortizations to prevent the collection of these dollars a second time. To ensure that these additional amortizations are identifiable in the future, Staff's recommends the Commission order Empire to assign the accumulated additional amortizations to Iatan 2 steam production plant depreciation reserve subaccounts. Specifically, Staff recommends the Commission order Empire to assign the $29,478,539 collected by Empire through November 30, 2010 to newly created accounts 311.5, 312.5, 314.5, 315.5, and 316.5 on a dollar-weighted Missouri jurisdictional cost basis of the prudently incurred additions to plant accounts resulting from the construction of Iatan 2, and assign to accounts 311.6, 312.6, 314.6, 315.6, and 316.6 the depreciation expense accruals resulting from applying the ordered depreciation rates to plant-in-service for Iatan 2. For each of the Iatan 2 accounts 311, 312, 314, 315, and 316 the subaccounts defined above are to be viewed as if the two subaccounts were a one account for depreciation analysis purposes. Retirement records for use in future depreciation studies shall be recorded and treated using the sum of the two subaccounts as one reserve account. The distribution to plant accounts recognizing Staff's recommended rate base for Iatan 2 is shown in the table below:

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[43] Staff defines generation production fleet as:

FERC-USOA Accounts	Generation Fleet Type
310-317	Fossil Steam
320-326	Nuclear Steam
330-337	Hydraulic
340-347	Other, Combustion Turbine, Solar, Wind

Electric Plant Chart of Accounts

Staff's Recommended Assignment of the Accumulated Additional Amortizations to the Reserves for Plant in Service Accounts

311.5	Structures and Improvements	10.43%	$ 3,075,045
312.5	Boiler Plant Equipment	46.99%	$13,852,465
314.5	Turbogenerator Units	7.8%	$ 2,298,461
315.5	Accessory Electrical Equip	7.7%	$ 2,291,502
316.5	Misc Power Plant Equip	27.01%	$ 7,961,066
TOTAL		100%	$29,478,539

g. Net Salvage Recording

Staff uses the following procedures to calculate net salvage by FERC account. Under the traditional accrual method, the depreciation rate for a particular asset or group of assets is calculated as follows:

$$\textit{Depreciation Rate} = \frac{100\% \;-\; \%\,\textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

In this formula, net salvage equals the gross salvage value of the asset minus the cost of removing the asset from service. The net salvage percentage is determined by dividing the net salvage experienced for a period of time by the original cost of the property retired during that same period of time. This is the accrual method used by Staff to determine the depreciation rate. To determine the amount of net salvage contained in accumulated depreciation as of December 31, 2003 as suggested in SFAS No. 143, Asset Retirement Obligations; Staff recommends that the net salvage amounts contained in accumulated depreciation as of December 31, 2003 be determined using the following formula for each account:

[Book Reserve * {(- *Net Salvage %) / (100% - Net Salvage %)}]*

Each year subsequent to 2003, net salvage accruals and gross salvage are added and removal costs are subtracted from the amount determined as of December 31, 2003. The annual net salvage accruals are determined using the following formula:

*[Depreciation Accruals * {(- Net Salvage %) / (100% - Net Salvage %)}],*

h. Recommendations

Staff recommends the Commission include in its Report and Order the following:

1. That Empire utilize the depreciation rates contained in Appendix 3, Schedule JAR(DEP)-3 and JAR(DEP)-5. These rates are premised on:

   i. Treatment of the majority of Empire's steam generation fleet as a living account, with mass asset, whole life depreciation rates, which include an allowance for net salvage.

   ii. Treatment of Iatan 2 as dying accounts, with life span, remaining life depreciation rates, based on:

      1. A 60 year life for Iatan 2.

   iii. Treatment of Empire's combustion turbine generation fleet as a living account, with mass asset, whole life depreciation rates, which include an allowance for interim and final retirements.

2. That Empire be ordered to create in its books the subaccounts identified in item 3 below.

3. That Empire be ordered to assign the $29,478,539 collected by Empire through November 30, 2010 to newly created accounts 311.5, 312.5, 314.5, 315.5, and 316.5 on a dollar weighted Missouri jurisdictional cost basis of the prudently incurred additions to plant accounts resulting from the construction of Iatan 2, and assigning to accounts 311.6, 312.6, 314.6, 315.6, and 316.6 the depreciation expense accruals resulting from applying the ordered depreciation rates to plant-in-service for Iatan 2.

4. That Empire be ordered to record in its books the reserve transfers for Iatan 2 identified in Section F: Regulatory Plan Amortizations of the depreciation section of the COS report and as follows:

311.5	Structures and Improvements	10.43%	$ 3,075,045
312.5	Boiler Plant Equipment	46.99%	$13,852,465
314.5	Turbogenerator Units	7.8%	$ 2,298,461
315.5	Accessory Electrical Equip	7.7%	$ 2,291,502
316.5	Misc Power Plant Equip	27.01%	$ 7,961,066
TOTAL		100%	$29,478,539

5. In its Report and Order issued January 11, 2005, in the remand of Case No. GR-99-315, the Commission directed "That Laclede Gas Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal." (Ordered paragraph 6) This decision by the Commission was

reaffirmed in the 2004 Empire case, Case No. ER-2004-0570. Staff asks that the Commission require Empire to keep a record by FERC plant account of amounts accrued for net salvage (cost of removal) in addition to the plant accumulated depreciation reserves, starting with an estimated amount as of December 31, 2003 as suggested in SFAS 143, Asset Retirement Obligations.

6. Staff requests that the Company adopt and maintain the data used by Staff for the depreciation study it undertook in this proceeding which was taken from the data provided for the ER-2004-0570 case with plant balances through December 31, 2003 and was updated for the years 2004 through December 31, 2009.

Staff Expert/Witness: John A. Robinett

F. Payroll and Benefits

1. FAS 87 and FAS 88 Pension Costs

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 No. 87 (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 and the *Stipulation and Agreement as to Certain Issues*, entered into in Case No. ER-2008-0093. Finally, this agreement was further modified by the *Non-Unanimous Stipulation and Agreement* entered into in Empire's last Missouri rate proceeding, File No. ER-2010-0130. 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. 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 in a consistent manner with the ratemaking treatment agreed upon by the signatories to the stipulation and agreements approved by the Commission in Empire's last four electric rate cases. Empire's rate base, as determined by the Staff, includes the FAS 87 Regulatory Asset, which represents the cumulative 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 $6,293,464.

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 November 30, 2010, was $1,782,616, which is to be amortized over five years as an expense in the amount of $356,523.

3. The amount to be included in rate base is $1,782,616, as noted above.

Staff Expert/Witness: Amanda C. McMellen

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 No. 106 (FAS 106). OPEBs primarily relate to medical benefits owed by Empire to Company retirees. This agreement was later modified by the *Stipulation and Agreement as to Certain Issues* reached in Case No. ER-2008-0093. This agreement was again further modified by the *Non-Unanimous Stipulation and Agreement* entered into in Empire's last Missouri rate proceeding, File No. ER-2010-0130. 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 the use of an OPEBs "tracker mechanism" to quantify the difference over time in the OPEBs rate allowance provided to the Company, and the Company's actual annual OPEBs expenses under FAS 106.

In this case, the Staff has complied with the terms agreed upon by the signatories to the stipulation and agreements approved by the Commission in Empire's last three electric rate cases 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 $1,559,331.

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 November 30, 2010, was ($2,123,156), which is to be amortized over five years as a reduction to expense in the amount of ($424,631).

3. Rate base is reduced by the level of regulatory liability, $2,123,156, as noted above.

Staff Expert/Witness: Amanda C. McMellen

3. Payroll, Payroll Taxes and 401K Benefit Costs

The Staff adjusted Empire's test year payroll expense to reflect an annualized level of payroll, payroll taxes, and 401(k) benefit costs as of November 30, 2010, but also included a non-union increase paid to Empire's employees that was effective in December 2010. The Staff is reflecting the December 2010 increase in its case because the decision to grant this increase was known and measurable by the end of the test year update period in this case (November 30, 2010), and the increase was paid to Empire's employees shortly after the end of the test year update period. In the Joint Proposal Regarding Certain Procedural Matters filed on November 15, 2010, it is stated "…Empire and/or Staff may propose an adjustment for certain non-union payroll increases now expected to take effect in December 2010. If such an adjustment is proposed, the other parties reserve the right to address it in testimony and pleadings and may oppose its inclusion in rates, but the other parties agree that they will not oppose it on the basis that it does not take effect until December of 2010, a point in time beyond the test period, as updated."

Base payroll was calculated by multiplying employee levels at November 30, 2010, 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 year average rate paid as of November 2010 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. An allocation rate for distributing the payroll adjustment was determined by using a three (3) year average of the percentage of Empire's total electric payroll costs. 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 November 30, 2010. 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 $3,613,396 required to restate the test year payroll to an annualized level as of November 30, 2010.

The Staff calculated payroll taxes based upon November 30, 2010 wage levels and current tax rates. This included Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA), and Federal Insurance Contributions Act (FICA) tax. 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 November 30, 2010.

Staff Expert/Witness: Casey Westhues

4. Incentive Compensation

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 certain pre-set goals. MIP awards were paid to Empire's officers in early 2010 for goals attained for calendar year 2009. 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, any awards associated with rates cases, and any awards Staff believed to be tied to normal job functions and levels of expected performance. 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, 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 at that time 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/Witness: Casey Westhues

G. Operations and Maintenance (O&M) Expenses for Iatan 2 and Plum Point

Iatan 2 met its in-service criteria on August 26, 2010, and Plum Point met its in-service criteria on August 13, 2010. Staff has included Empire's current estimated annualized amounts for Empire's share of Iatan 2 and Plum Point O&M expenses in its recommended revenue requirement in this case.

Staff recommends the Commission authorize a "tracker" mechanism be used for Iatan and Plum Point O&M expenses, so the actual cost of O&M expense related to each plant can be recovered through rates for both the ratepayer and Company in future rate cases. Given Empire's limited operating experience with Iatan 2 and Plum Point at this time, a tracker protects both Empire and its customers from the risk associated with including projected costs in rates that are likely to vary from the actual O&M expense incurred for the two generating units. Tracker treatment should not, however, be granted to those components of the plant O&M costs that will be flowed through Empire's FAC, such as "consumables" and SO2 emission allowances.

A portion of Empire's cost for obtaining power from the Plum Point unit through a long-term purchased power agreement is intended to cover a proportionate amount of unit O&M expense, which is in addition to the portion of O&M costs that Empire is responsible for due to its 7.52% ownership of Plum Point. However, the Staff's fuel and purchased power model does not take into account the O&M component of Empire's Plum Point purchased power cost.

Therefore, Staff had to make a separate adjustment in its Accounting Schedules to include these costs in its case. Empire's ownership share of this unit (7.52%) is almost identical to its right to 7.50% of the unit's power (50 megawatts). For this reason, the amount of Plum Point O&M expense related to its purchased power agreement for that unit in the Staff's case is almost exactly equal to the amount of O&M expense included in this case for Empire associated with its ownership of the Plum Point unit that is discussed above. However, unlike its ownership related share of O&M expenses, the Staff is not proposing to included the Plum Point purchased power-related O&M in a tracker mechanism, since purchased power costs flow through the FAC.

Staff Expert/Witness: Keith D. Foster

H. Other Non-Labor Expenses

1. Rate Case Expenses

The Staff has included the actual costs incurred by Empire for rate case expense as of November 30, 2010, for this case, File No. ER-2011-0004. 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 Staff's proposed adjustments to the costs booked to Account 928 for Federal Energy Regulatory Commission (FERC) expenses and the PSC annual assessment.

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 to normalize rate case expense over four years, the period of time between when Empire believes it will be filing another rate case.

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/Witness: Casey Westhues

<u>2. Infrastructure - Tree Trimming (Vegetation Management)</u>

In 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) and infrastructure inspection costs compared to an estimated target annual amount of $8,575,000. In the *Stipulation and Agreement* in the last rate case, File No. ER-2010-0130, the Staff and the Company agreed to continue the vegetation tracker, but terminate the infrastructure tracker approved in the 2008 rate case. The Staff proposed adjustments to expense to amortize the Case Nos. ER-2008-0093 and ER-2010-0130 tracker assets over a five-year period, in the amount of $292,514 and $197,789 respectively.

Per the terms of the *Stipulation and Agreement* in File No. ER-2010-0130, filed May 12, 2010 the vegetation management tracker will continue until at least Empire's next Missouri rate proceeding.

In the last rate case, File No. ER-2010-0130, Empire proposed to recover certain "remediation" costs through the vegetation/infrastructure tracker. These remediation costs were allegedly incurred as a result of the Company performing preventive maintenance on their transmission and distribution system during the inspection cycles mandated under the infrastructure inspection rule. In the last case, the Staff opposed inclusion of these costs in the tracker because it did not believe this type of expense was truly solely attributable to the new infrastructure inspections rule. In this case, the Company proposed an adjustment to include additional remediation costs in its case on the basis that the mandated inspection requirements would result in an increase in its ongoing level of repair costs to its equipment. The Staff reviewed these costs in this case, and concludes that the Company's belief appears to be valid. Accordingly, the Staff has annualized these newly incurred non-labor remediation costs and is proposing an adjustment to increase expense in the amount of $154,824.

The Staff has also included in its case an addition to Rate Base in the amount of the adjusted vegetation and infrastructure tracker balance as of November 31, 2010. (*see* Section VI. K.).

Staff Expert/Witness: Paul R. Harrison

3. Customer Deposit Interest Expense

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

Staff Expert/Witness: Casey Westhues

4. 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 January 1, 2010, except for certain major plant additions made by Empire later in the year as discussed later. 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, 2010. This property tax rate was then applied to total electric plant in service on January 1, 2010, 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.

The Staff's normal approach to calculation of property taxes for ratemaking purpose is to apply a reasonable property tax rate to the latest January 1 balance of plant in service reflected within an ordered test year, test year update period or true-up period. This approach is consistent with the actual method used by taxing authorities to bill and collect property taxes. However, in this case, Empire added significant additions to its plant, primarily the Plum Point and Iatan 2 generating stations, which will in turn materially increase Empire's property tax expense. As previously discussed, the test year update period for this case ends at November 30, 2010. In lieu of proposing an "isolated adjustment" outside of the test year update period in its case to incorporate Plum Point, Iatan 2 and Iatan 1 environmental and Iatan common plant balances as of January 1, 2011 in its property tax calculations, the Staff has taken a conservative approach and added the October 31, 2010 balances for these plant additions to its property tax expense calculation for this case.

Staff Expert/Witness: Casey Westhues

<u>5. Bad Debt Expense</u>

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 examined the actual seven-year and eleven-month (2003-2010) 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 trend in this item. From the information provided 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.

Staff Expert/Witness: Amanda C. McMellen

6. Amortization Expense

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 November 30, 2010, (as described earlier in Section VI. G.).

Staff Expert/Witness: Amanda C. McMellen

b. Amortization of Stock Issuance Costs

In 2006, 2007, 2008, 2009 and 2010 Empire made additional issuances of common equity, with the issuance in 2010 worth approximately $150,000,000. In making all of these issuances, the Company incurred costs totaling $7,574,871 (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/Witness: Amanda C. McMellen

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 expensive 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.

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.

Staff Expert/Witness: Amanda C. McMellen

7. Demand Side Management Cost Recovery-Low Income Weatherization

a. Background and Status of Empire's Demand-Side Management Programs

Empire began implementing its current demand-side management (DSM) programs in 2005 as a result of the Commission's *Order Approving Stipulation and Agreement* in Case No. EO-2005-0263. The *Order* approved Empire's regulatory plan that included 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") also part of the Regulatory Plan. Members of the CPC include Empire, Staff, Office of the Public Counsel (OPC), Missouri Department of Natural Resources and the 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[44]. Empire's regulatory plan included an expiration date as of the effective date of the initial rates that reflect inclusion of the Iatan 2 investment, expected to be August 25, 2011, the operation-of-law date for rates in this case.

On September 15, 2010, Staff provided to the Commission a *Status Report* concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives (File No. AO-2011-0035). Attached to this Staff COS Report as Appendix 3, Schedule JAR-1 are pages from the *Status Report* that highlight Empire's CPC process, Empire's eight (8) implemented DSM programs and the challenges and successes to date of Empire's DSM programs. In addition to the DSM programs described in Appendix 3, Schedule JAR-1, Empire has a voluntary Interruptible Service Rider demand response program

[44] Commission's August 2, 2005 Order Approving Stipulation and Agreement, Case No. EO-2005-0263, Attachment 1: Empire Experimental Regulatory Plan Stipulation and Agreement, pp. 25-30, July 18, 2005.

that was first implemented in 2009; and Empire added Apagee HomeEnergy Suite and Commercial Energy Suite features to its website, including energy calculators and libraries that provide energy efficiency educational information to residential and commercial customers.

Empire budgeted $1,669,644 for its 2010 DSM programs, Interruptible Service Rider and Apagee Suites, and spent $1,139,387, or approximately 0.3 percent of Empire's 2010 Missouri jurisdictional gross revenue[45], on DSM programs.

The energy and demand impacts and the overall delivery processes of Empire's DSM programs are evaluated, measured and verified ("EM&V") by third-party contractors chosen and paid for by Empire. To date, EM&V reports have been completed and provided to CPC members for five of Empire's eight DSM programs.

Empire witness Sherrill L. McCormack provides in her direct testimony a summary of the annual estimated energy savings as a result of Empire's DSM programs. Staff provides the following summary of Empire's estimated Missouri annual energy savings as a percent of total Missouri jurisdictional energy sales, calculated from the last four years of complete Company annual data in the Staff's possession:

Empire's Estimated Missouri Annual Energy Savings and Missouri Annual Energy Sales

	2006	2007	2008	2009
Estimated Energy Savings MWh (1)	996	1,738	4,194	5,942
Missouri Sales MWh (2)	4,155,082	4,223,934	4,223,367	4,036,696
Percent Energy Savings	0.02%	0.04%	0.10%	0.15%

(1) Sherrill L. McCormack direct testimony, page 9 line 4, File No. ER-2011-0004
(2) Annual Report of The Empire District Electric Company , FERC Form 1

Staff notes that although the relative amount of Empire's energy savings has increased each year since 2006, the 2009 energy savings level of 0.15 percent of total energy sales is relatively low for an electric utility that has been implementing DSM programs for at least four full years.

[45] Based on 2010 Empire total Missouri retail revenue of $384,176,367.

b. Empire's DSM Resources in Its 2010 Chapter 22 Compliance Filing

Empire filed its latest Chapter 22 compliance filing in September 2010 in File No. EO-2011-0066 ("2010 Chapter 22 compliance filing"). The following table illustrates that Empire's adopted preferred resource plan continues to have relatively low levels of energy savings throughout the 20-year planning horizon.

Empire's Estimated Missouri Annual Energy Savings and Forecasted Missouri Annual Energy Sales In Empire's Latest Chapter 22 Compliance Filing

	2011	2012	2013	2014
Estimated Energy Savings MWh (1)	6,466	10,092	13,809	17,110
Forecasted Missouri Sales MWh (1)	5,572,169	5,681,232	5,795,282	5,911,623
Percent Energy Savings	0.12%	0.18%	0.24%	0.29%

	2015	2020	2025	2029
Estimated Energy Savings MWh (1)	20,700	30,506	49,401	68,791
Forecasted Missouri Sales MWh (1)	6,038,722	6,792,338	7,684,905	8,482,697
Percent Energy Savings	0.34%	0.45%	0.64%	0.81%

(1) Midas Models for adopted preferred resource plan File No. EO-2011-0066

During its review of Empire's 2010 Chapter 22 compliance filing, Staff identified the root cause of Empire's relatively low estimates of energy savings in its adopted preferred resource plan. The DSM market potential study performed by Applied Energy Group, Inc., included a management-imposed budget constraint on the Company's level of DSM spending.

At the time of this filing, Empire, Staff and other parties are in the process of attempting to reach a joint agreement to remedy all deficiencies and concerns related to Empire's 2010 Chapter 22 compliance filing.

c. DSM Cost Recovery

Empire's Regulatory Plan includes the following specific accounting and ratemaking treatment for Customer Programs costs[46]:

> 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.

Empire's Regulatory Plan will expire on the effective date of the initial rates that reflect inclusion of the Iatan 2 investment, expected to be August 25, 2011, the operation-of-law date for rates in this case. However, cost recovery for this rate case is under the direction of the Regulatory Plan.

d. Missouri Energy Efficiency Investment Act of 2009 ("MEEIA")

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

[46] (*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).

MEEIA rules on December 20, 2010, and sent its proposed MEEIA rules to the Missouri Joint Committee on Administrative Rules on February 10, 2011.

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

With the passage of the enactment of MEEIA, the State of Missouri has declared and directed the following:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.
>
> Subsections 393.1075.3 and 4, RSMo. Supp. 2009.

While Staff does not view Empire's existing demand-side programs presently to be demand-side programs proposed pursuant to section 393.1075.4, RSMo. (Supp. 2009), and since Empire did not ask for treatment of demand-side cost recovery under MEEIA, current accounting treatment of Empires demand-side programs' costs and the amortization over ten years should be continued as prescribed in the Regulatory Plan until the Commission has rules in effect to implement MEEIA.

e. Staff Review and Recommendation

Empire has worked cooperatively with the CPC members to implement eight (8) DSM programs and one (1) demand response program over the past five years. Therefore, Staff believes it is no longer necessary or efficient to continue the voting aspect of the CPC. However, Empire has achieved relatively low levels of energy savings from its DSM programs during the first five years of DSM programs implementation. Further, Empire's current adopted preferred resource plan does not materially change Empire's planned low level of energy savings over the 20-year planning horizon due to a management directive to constrain spending on DSM programs. For these reasons, Staff believes the current regulatory asset account and ten year amortization should continue until Empire is able to achieve or has a plan to achieve much higher energy savings from its DSM programs. As a result of its review, Staff recommends that the Commission:

1. Not change the current Empire DSM cost recovery mechanism including the ten year amortization;

2. Change the current Empire Customer Program Collaborative to be a customer program advisory group; and

3. Encourage Empire to work diligently with CPC members to take steps necessary to comply with the MEEIA goal of achieving all cost-effective demand-side savings and to prepare to file its applications for approval of DSM programs and demand-side program investment mechanisms under the soon-to-be effective MEEIA rules.

Staff Expert/Witness: John A. Rogers

f. 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 Interruptible Service Rider ("IR") demand response program. The IR is a voluntary commercial and industrial load curtailment program. The Company makes monthly payments/credits to customers based upon the contract term of each customer. This program allows Empire to call for curtailment for emergency and for economic reasons. The IR has three participants, but there were no requests from Empire in 2010 to interrupt service under the IR.

Staff Experts/Witnesses: Amanda C. McMellen and Hojong Kang

g. Low-Income Weatherization

There are specific programs designed to help low-income customers with energy conservation. Low-income consumers often live in housing that is energy inefficient with substandard insulation and other deficiencies. These customers would benefit from building shell energy conservation measures such as weatherization or more energy-efficient appliances. The Low Income Weatherization Assistance Program ("Weatherization Program") is administered by the Missouri Department of Natural Resources (MDNR) using federal, state, and utility funding. The Weatherization Program is administered locally by Community Action Agencies or other local agencies ("Weatherization Agencies"). In Empire's service area the Weatherization Program is administered by the Economic Security Corporation, the Ozark Area Community Action Corporation, and the West Central Missouri Community Action Agency.

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

The Weatherization Agencies are making a concerted effort to utilize the ARRA funding before the March 2012 deadline.

Funding for a five-year (2006 - 2010) Weatherization Program was originally part of Empire's Regulatory Plan approved by the Commission in Case No. EO-2005-0263. This level of funding was also authorized in subsequent rate cases, the most recent being the Commission's Order in Case No. ER-2010-0130. The annual expenditures have been close to the annual funding. Although there has been some year-to-year carryover of funds, the carryover from previous years has subsequently been expended so there has not been any buildup of unexpended funds. Empire used only a small portion of the budgeted Marketing/Project Management Funds for the Weatherization Program and accumulated the unspent funds. Consequently, for the final Regulatory Plan Weatherization Program Year, 2010-2011, Empire has reallocated the Marketing Funds to the Weatherization Program fund for use by the Weatherization Agencies and extended the 2010-2011 program period from twelve months to fifteen months ending in December 2011 (Appendix 3, Schedule HEW-1).

The Weatherization Program was evaluated and the results presented in a report, *An Evaluation of the Low-Income Weatherization Program, Results of an Impact Evaluation,* Prepared for Empire District Electric Co., Johna Roth. TedMarket Works, Oregon, WI, March 16, 2009. The findings of the evaluation were generally positive, with an average annual net savings from the weatherization services of 2,052 kWhs. The only recommendation by the evaluator was that compact fluorescent lights (CFLs) be included as a measure in the Weatherization Program.

There is no sizeable under-utilization of utility funds because of the Weatherization Agencies' focus on using the ARRA funding. At the end of the ARRA period, the Weatherization Agencies anticipate using any surplus utility funds to help provide for a higher level of weatherization activity than before ARRA.

Given the positive evaluation of the Empire Weatherization Program by an independent evaluator, the ability of the Company to see that the funding is utilized by the Weatherization Agencies, and the additional measure of including CFLs as a measure in the Weatherization program, Staff does not oppose Empire's proposed increase in annual budget of $226,430 from $201,300 for the Weatherization Program for 2012 and succeeding years allocated among the Weatherization Agencies by the process contained in the Weatherization Program tariff sheets.

Because it is an energy efficiency program, recovery of Weatherization Program expenditures should be in the same method as recommended by Staff witness John A. Rogers for the other Empire demand side management programs.

Staff Expert/Witness: Henry E. Warren, PhD

8. Entergy Transmission Contract

Empire has a contract with Entergy Solutions, Inc. for Firm Point-to-Point Transmission Service to transmit power generated from the Plum Point Energy Station to Empire. Staff included an adjustment that annualizes the cost of this service.

Staff Expert/Witness: Keith D. Foster

I. 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 most recent rate case, No. ER-2010-0130. 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 term "timing differences" refers to the differences in time when certain costs can be deducted for purposes of determining financial statement net income and taxable income, respectively.) The adjustments are the result of various financial statement (or "book) and 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 (6.25%)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.

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

SWPA Capacity Loss Reimbursement (three-year amortization)

50% Meals and Entertainment

Contributions in Aid of Construction

Book Amortizations

Subtractions from Operating Income:

Interest Expense

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. Current IRS rules for regulated utilities in effect 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 in this rate case consists of three components:

1. IRS Schedule M timing differences: contributions in aid of construction This amount is normalized consistent with Staff's calculation in the prior rate case filing.

2. Depreciation tax timing difference the 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 (TRA): Enactment of the TRA 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.

In most rate cases, a combination of the above three components make up the amounts recorded as deferred income tax expense.

Staff Expert/Witness: 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 heavy construction activity from 2005 to 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 provision that the signatories to Empire's regulatory plan agreed to support inclusion in Empire's rates of additional amortizations if Empire did not meet certain financial ratios in any general rate case filed prior to the Iatan 2 rate case. Additional amortizations were included in Empire's revenue requirement in File Nos. ER-2006-0315, ER-2008-0093, and ER-2010-0130. The instant Empire rate increase application is the case described in Section III.D.7(a) of Empire's regulatory plan,[47] thus Staff is not recommending the inclusion of and new additional amortizations in Empire's revenue requirement. Staff has removed the cumulative additional amortizations from its calculation of Empire's expenses in this case. Empire's

[47] This was stipulated in the *Stipulation and Agreement*, filed February 25, 2010, in File No. ER-2010-0130.

collection of additional amortizations will cease when new rates go into effect as a result of this proceeding.

Staff is including the total dollar value of accumulated additional amortizations collected from Empire's customers to date as an offset to rate base. The total dollar value of Empire's accumulated additional amortizations is $29,478,539 as of November 30, 2010, the end of the update period for this case.

Staff recommends that the total dollar value of the additional amortizations collected from Empire's customers pursuant to Empire's regulatory plan be included in Empire's Iatan 2 depreciation reserve and be used to offset rate base for the entire time the Iatan 2 unit is included in Empire's rate base. Empire should be ordered to separately identify the accumulated additional amortization component of the Iatan 2 depreciation reserves over time so that this component never loses its "identity" during the unit's useful life by being intermingled with normal booking of depreciation reserves associated with this unit. The proposed inclusion of the regulatory plan amortizations in the Iatan 2 depreciation reserves is further discussed in Section VIII.E., Depreciation, of this Report.

Staff Expert/Witness: Mark L. Oligschlaeger

X. Fuel Adjustment Clause (FAC)

A. Recommendation

Staff recommends the Commission approve, with modifications, the continuation of Empire's Fuel Adjustment Clause (FAC). Staff has reviewed the documents the Company provided in Schedules WSK-5 and WSK-6 attached to the prefiled direct testimony of Company witness W. Scott Keith, and believes that with these documents the Company has complied with the FAC minimum filing requirements contained in 4 CSR 240-3.161(3) to inform the public of Empire's proposed FAC. Empire also complied with the heat rate testing requirements contained in 4 CSR 240-3.161(3)(Q).

Staff recommends the Base Cost factors in Empire's FAC be calculated using the costs included in the revenue requirement upon which its general rates are set in this case for fuel, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowance revenues, and renewable energy credit revenues (collectively, "FAC Fuel Costs"), and annualized, normalized net system input calculated for the true-up total revenue requirement for this case.

In this testimony, Monthly Base Cost[48] is defined to be the monthly fuel and purchased power costs plus system net emission allowance costs and revenues less off-system sales revenue and renewable energy credit revenues Staff used to develop the revenue requirement for Empire in this case. At this time Staff does not have estimates for the Monthly Base Costs, but will have them before Staff files its Class Cost of Service and Rate Design Report in March 16, 2011. Staff will use the Monthly Base Costs to develop the appropriate summer and winter Base Cost factors ("Base Cost factors") to include in its Class Cost-of-Service and Rate Design Report.

Staff recommends that the Company's FAC tariff be modified to: 1) change the sharing mechanism from 95%/5% to 85%/15% to provide the Company with a more appropriate incentive to minimize its fuel and purchased power costs, and 2) include summer and winter Base Cost factors in the FAC tariff sheets calculated from the summer and winter Base Costs in the true-up total revenue requirement in the rate case to assure that the Company does not over- or under-collect as a result of the Base Cost factors in the FAC not matching with the Base Costs used to set permanent rates in this rate case. In addition the Staff provides a listing of information that it recommends that the Commission order the Company to continue to provide or make available information and documents to assist Staff during its performance of FAC tariff, prudence and true-up reviews.

B. Summary of Current FAC

The Commission first authorized a FAC for Empire in its *Report and Order* in Empire's 2008 rate case (Case No. ER-2008-0093), and approved FAC tariff sheets in that case an

[48] Base Cost is defined in Empire's tariff sheet 17d as "Company generated energy and purchased energy cost per kWh at the generator, established by season in the most recent base rate case." Base Cost is also defined on tariff sheet 17e as a dollar amount calculated as follows:

1. For the months of June through September B = (NSI kWh * $0.03182)

2. For all other months B = (NSI kWh * $0.02857)

For the purposes of this report "Base Cost" refers to the dollar amount and "Base Cost factor" refers to energy cost per kWh at the generator.

effective date of September 1, 2008. In Empire's 2010 rate case, File No. ER-2010-0130, the Commission authorized continuation, with modifications, of Empire's FAC. The primary features of Empire's present FAC (tariff sheet numbers 17 through 17g) include:

- Two 6-month accumulation periods: March through August and September through February;
- Two 6-month recovery periods: December through May and June through November;
- Two Cost Adjustment Factor (CAF) filings annually not later than April 1 and October 1;
- Two Base Cost factors: one for the summer calendar months of June through September (referred to herein as "summer Base Cost factor") and one for all other calendar months of the year (referred to herin as "winter Base Coast factor")..
- A 95%/5% sharing mechanism;
- CAF rates for individual service classifications adjusted for the two Empire service voltage levels, rounded to the nearest $0.00001, and charged on each kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with true-up amount being included in the determination of CAF for a subsequent recovery period.

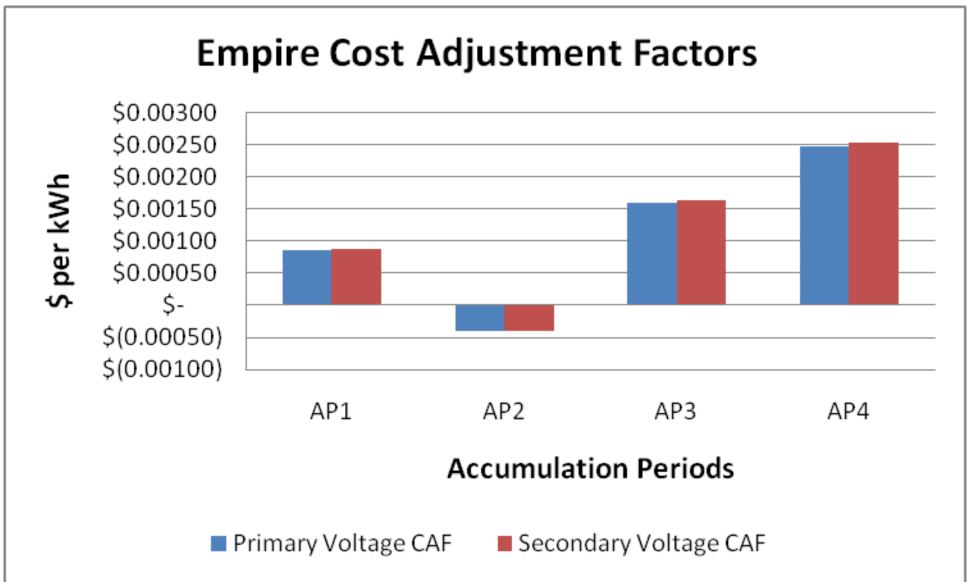
Empire has made four CAF filings (File Nos. EO-2009-0348, ER-2010-0105, ER-2010-0275, and ER-2011-0095), and the resulting changes to the Empire CAFs ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The Base Cost factors were originally set in Empire's 2008 rate case and were changed as a result of the settlement of Empire's 2010 rate case.

Staff has filed one prudence review report concerning its review of the costs and revenues of the Company's FAC and found no evidence of imprudent decisions by the Company's management related to procurement of fuel for generation, purchased power, emission allowances, and off-system sales for the time period reviewed. Staff's prudence review report is in File No. EO-2010-0084, and covers the period September 1, 2008 through August 31, 2009.

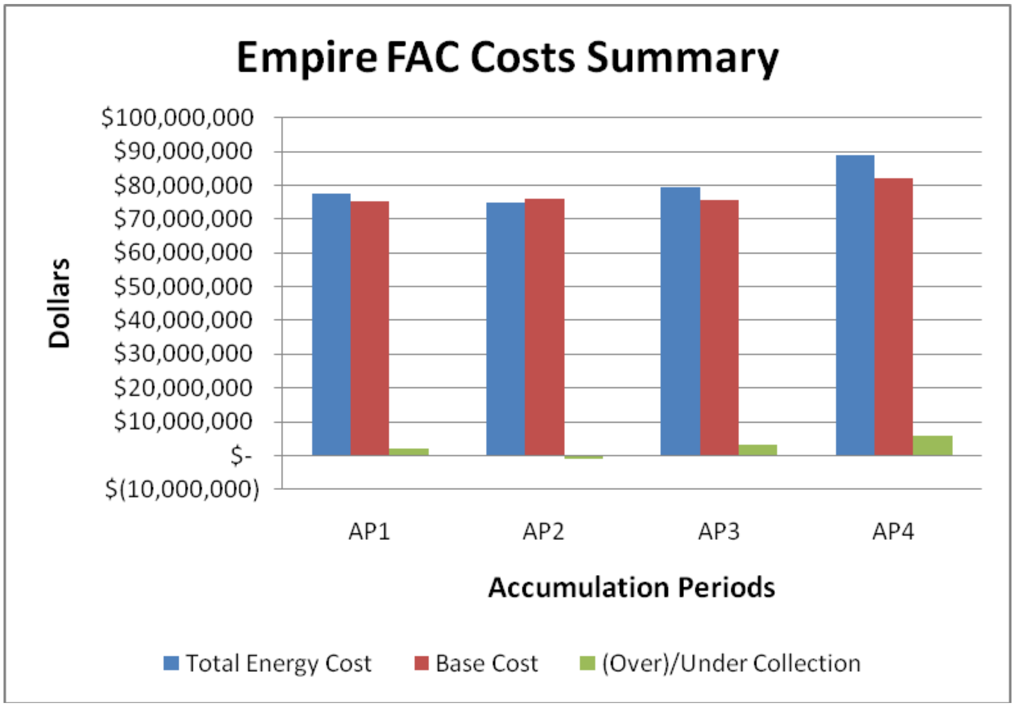
C. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of Empire's FAC.

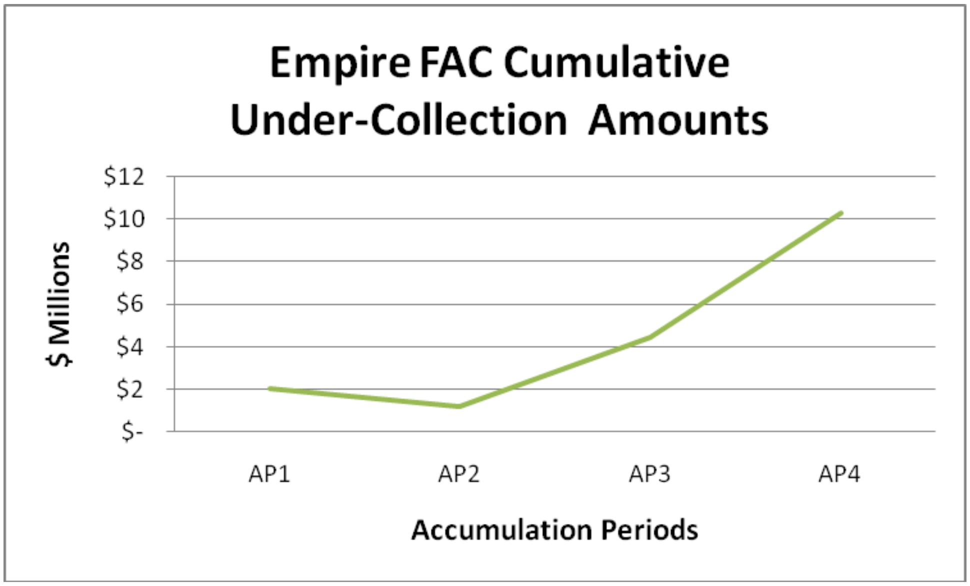
The Company has filed for and received approval of changes to its CAFs for four completed accumulation periods (AP1, AP2, AP3, and AP4). The primary and secondary voltage CAFs for each accumulation period are reflected in the following chart:

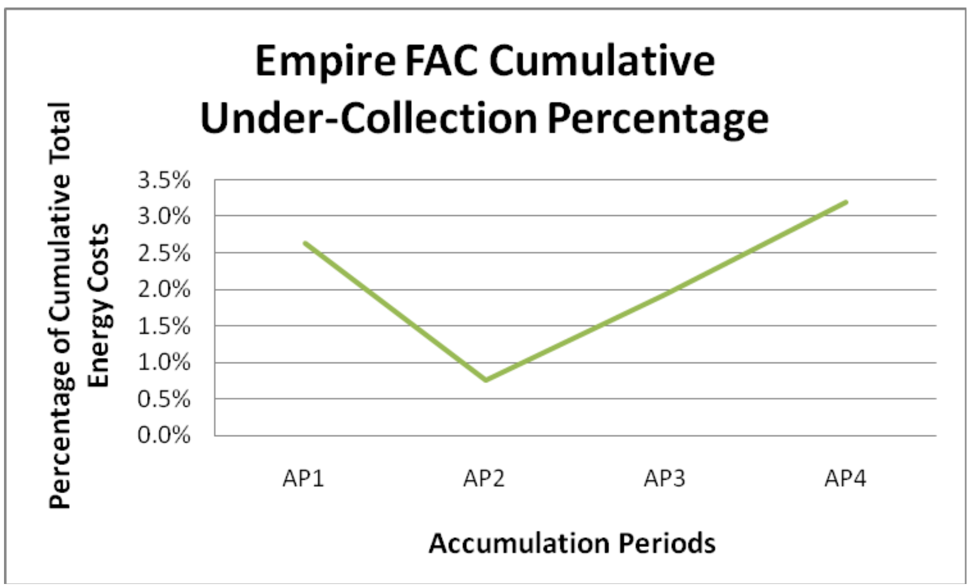


The Company's total energy costs in each accumulation period — Empire's total book costs as allocated to the Missouri retail jurisdiction for fuel consumed in Company generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs; but not including the purchased power demand costs; as off-set by off-system sales revenue, any emission allowance revenues collected, and renewable energy credit revenues have exceeded the appropriate Base Cost factors (summer and winter) multiplied by monthly usage billed to Empire's customers' in three out of four completed accumulation periods. During AP2, Empire's summer and winter Base Cost factors multiplied by customer usage in the appropriate months exceeded total energy cost; 95% of the difference was credited to customers during Recovery Period 2. The following chart illustrates Empire's total energy costs, the sum of the appropriate Base Cost factors in the FAC tariff multiplied by the monthly kWhs during accumulation period and the difference between them — the "over/under collection" amounts, for each of the four accumulation periods:



The next two charts illustrate the following information for the first four accumulation periods: 1) cumulative amount of the difference between total energy costs and the Base Cost factors multiplied by kWh usage as calculated in accordance with Empire's FAC tariff sheets, and 2) percentage of cumulative over/under-collection of the difference between total energy costs and the Base Cost factors in Empire's FAC tariff sheets multiplied by the kWh usage in accumulation period kWh:





From the above information, Staff observes that the FAC under-collected amount over two years is $10.2 million (3.2 percent (3.2%) of total actual energy costs of $321 million). Staff's analysis and discussion in the **Sharing Mechanism of FAC** section which follows suggests that without the FAC Empire would have lost approximately 7.1 percent (7.1%) of its test year net income before taxes[49] due to under-collection of total energy costs over the first four accumulation periods. In the *Stipulation and Agreement* in Empire's last rate case, File No.

[49] Net income before taxes in Staff Accounting Schedules for Empire's True-up Income Statements in File No. ER-2010-0130 of $72,209,297.

ER-2010-0130, the Company agreed with Staff to reset, i.e., rebase the Base Cost factors in its FAC based on costs in the revenue requirement upon which the Commission set Empire's general rates — FAC Fuel Costs. This is not reflected in the graphs above as the Base Cost factors for Case No. ER-2010-0130 went in effect September 10, 2010. AP5 spans the time period of September 1, 2010 through February 28, 2011. With this rebasing, it is expected that the under-collection of total energy costs will decrease in AP5.

D. Sharing Mechanism of FAC

Staff proposes changing Empire's current 95%/5% FAC sharing mechanism to an 85%/15% FAC sharing mechanism.

In its Report and Order in a recent Ameren Missouri rate increase case — File No. ER-2010-0036 — the Commission concluded:

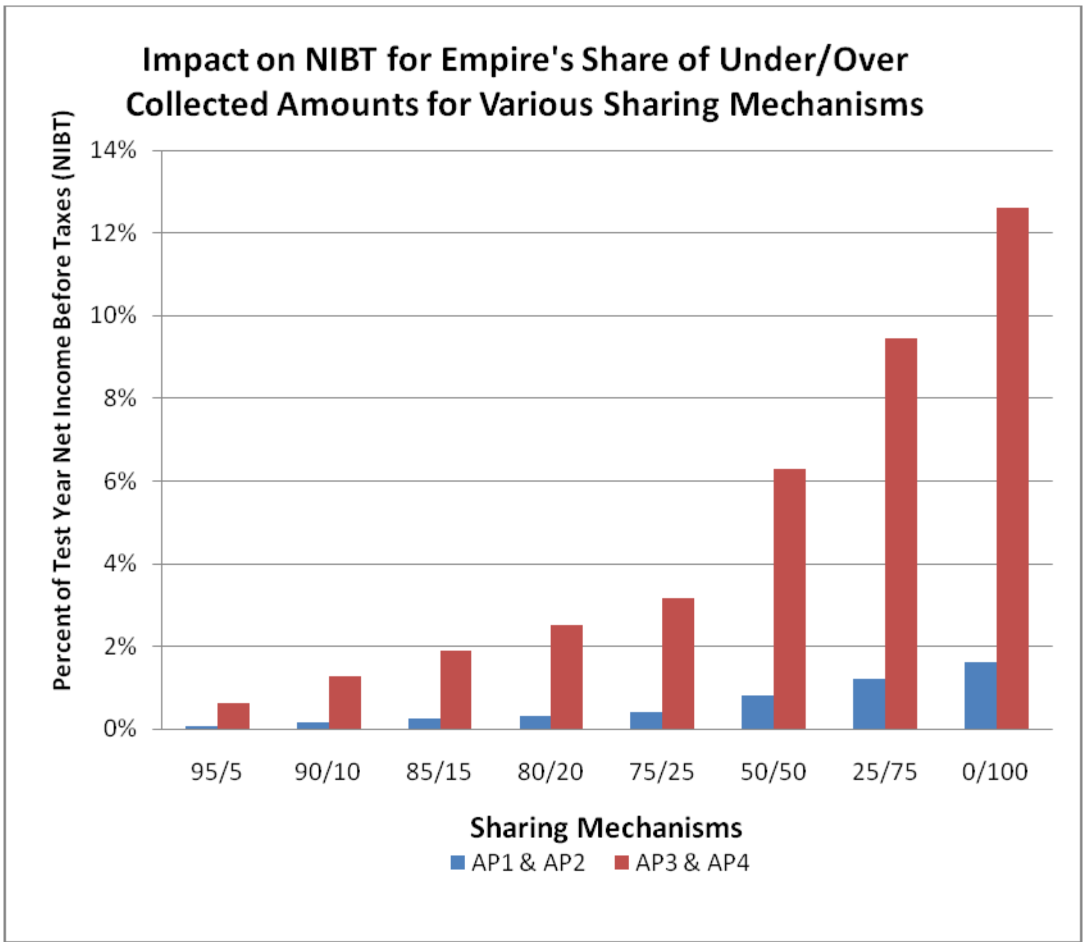
> AmerenUE should be allowed to continue to implement the fuel adjustment clause the Commission approved in the company's last rate case. Given the short amount of time AmerenUE's fuel adjustment clause has operated and the resulting lack of information about how effective the current sharing mechanism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

In Empire's last rate case filed October 2009, File No. ER-2010-0130, Staff was in a similar position regarding Empire's FAC as it was in Ameren Missouri's last rate case. The FAC had been in effect a little over a year and not enough time had passed for Staff to provide a meaningful analysis of the 95%/5% sharing mechanism to the Commission. Empire's FAC has now been in effect for over two years which provides Staff with more information to evaluate the impact of the current 95%/5% Empire FAC sharing mechanism over the first four accumulation periods and to evaluate several other selected sharing mechanisms for the impact they would have had on the Company's test year net income before taxes.

The objective of the FAC sharing mechanism is to provide an incentive for the Company to develop and manage an effective energy procurement process which minimizes energy costs while managing risk of loss of energy supply. The Commission expressed its view in its *Report and Order* in File No. ER-2008-0093 where it first established Empire's current 95%/5% sharing mechanism, starting on page 44:

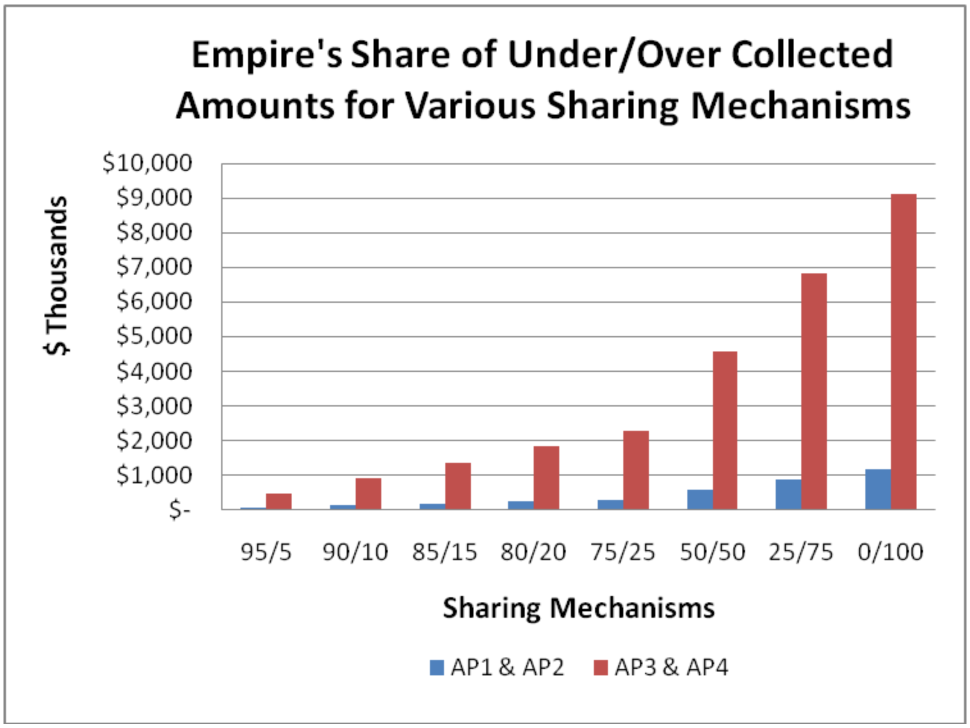
> The goal of all these pass through plans is to ensure that Empire retains sufficient financial incentive to make a strong effort to reduce its fuel and purchased power costs. If all such costs can be passed 100 percent to customers, Empire's incentive to control those costs is reduced.

Staff has evaluated the impacts on Empire's test year net income before taxes of Empire's FAC over the first four accumulation periods with the current 95%/5% sharing mechanism, and with several other selected sharing mechanisms. Staff proposes changing the current 95%/5% FAC sharing mechanism to an 85%/15% sharing mechanism. The results of Staff's comparison of the impact to net income before taxes of various sharing mechanisms are shown the chart below:



Through this analysis Staff estimates that Empire's 5% share of the total under-collection amount of approximately $10.2 million during the first four accumulation periods is $513,687 and represents 0.4% of the test year net income before taxes ($144 million) for this same period of time. Similarly, Staff estimates that for Company shares of 10%, 15%, 20%, 25%, 50%, 75%, and 100% of the total under-collection amount during the first four accumulation periods represent approximately 0.7%, 1.1%, 1.4%, 1.8%, 3.6%, 5.3%, and 7.1% of the test year net income before taxes for this same period of time.

The corresponding dollar amounts of the total under-collected amount of $10.2 million during the first four accumulation periods that the Company would have been responsible for if the Company's share had been 10%, 15%, 20%, 25%, 50%, 75%, and 100% is illustrated in the following chart.



Staff considers the annual under-collected amount to be an insufficient incentive for the Company to reduce its fuel and purchased power costs; an average of $256,843 out of an average annual total FAC cost of $5.1 million under the current 95%/5% sharing mechanism during the first four accumulation periods.

To further illustrate the lack of incentive with the current 95%/5% sharing mechanism, Staff points out that neither in this rate case nor in its last rate case did Empire propose to reset its Base Cost factors in the FAC it proposed in its direct testimony or in its test year total revenue requirement that it filed as part of either rate case.[50] For AP3 and AP4, Empire was responsible for $455,262 of the under-collected amount. This was not significant enough for Empire to

[50] This issue is referred to as "rebasing" the FAC.

choose to rebase the Base Cost factors in this current rate case. It is Staff's position that Empire's failure to rebase its Base Cost factors is an indication of the inadequacy of the current sharing mechanism.

Staff recommends an 85%/15% sharing mechanism, which, all else remaining the same, for the first four accumulation periods would have resulted in the Company being responsible for an average of $770,530 annually of the under-collected amount of the FAC. Measured differently, this is approximately 1.1% of test year net income before taxes and 0.5% of Empire's total energy costs during that same period. Staff considers an 85% share of FAC over/under collection amounts to be a point where Empire begins to take on a more meaningful portion of the risk of actual FAC costs. By being responsible for 15% of FAC over/under collection amounts, Empire would have a more appropriate incentive to keep its fuel and purchased power costs down and to minimize total energy costs while managing risk of loss of energy supply.

Staff notes that before the Commission authorized Empire's FAC, Empire was responsible for 100% of fuel and purchased power cost variation between rate filings. With Commission authorization of its FAC, 95% of the responsibility or any over/under collection of total energy costs shifted from the Company to its customers. Given the information available at the time of this filing, Staff's 95%/5% sharing mechanism recommendation when Empire first sought an FAC was shifting too much risk from the electric utility to its customers. It is Staff's opinion, given the information available at the time of this filing, that an 85%/15% sharing mechanism appropriately balances the risk and interest between the shareholder and ratepayer.

E. Importance of Resetting the Base Cost Factors

Correctly setting the Base Cost factors in Empire's FAC tariff sheets is critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism. Staff recommends the Commission require the Base Cost factors in Empire's FAC be set based on the FAC Fuel Costs the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case.

The table below shows three cases in which the FAC Fuel Costs used to set the FAC Base Cost factors are equal to, less than or greater than the FAC Fuel Costs in the revenue requirement upon which the Commission sets general rates:

Line	**85%/15% Sharing Mechanism Example**	**Case 1**: Base Energy Cost in FAC **Equal To** Base Energy Cost in Rev. Req.	**Case 2**: Base Energy Cost in FAC **Less Than** Base Energy Cost in Rev. Req.	**Case 3**: Base Energy Cost in FAC **Greater Than** Base Energy Cost in Rev. Req.
a	Revenue Requirement	$10,000,000	$10,000,000	$10,000,000
b	Base Energy Cost in Rev. Req.	$4,000,000	$4,000,000	$4,000,000
c	Base Energy Cost in FAC	$4,000,000	$3,900,000	$4,100,000
	Outcome 1: Actual Energy Cost **Greater Than** Base Energy Cost in Revenue Requirement			
d	Actual Energy Cost	$4,200,000	$4,200,000	$4,200,000
	Billed to Customer:			
= b	in Permanent Rates	$4,000,000	$4,000,000	$4,000,000
e = (d - c) x 0.85	through FAC	$170,000	$255,000	$85,000
f = b + e	Total Billed to Customers	$4,170,000	$4,255,000	$4,085,000
g = f - d	**Kept/(Paid) by Company**	**$(30,000)**	**$55,000**	**$(115,000)**
	Outcome 2: Actual Energy Cost **Less Than** Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	$3,800,000	$3,800,000	$3,800,000
	Billed to Customer:			
= b	in Permanent Rates	$4,000,000	$4,000,000	$4,000,000
i = (h - c) x 0.85	through FAC	$(170,000)	$(85,000)	$(255,000)
j = b + i	Total Billed to Customers	$3,830,000	$3,915,000	$3,745,000
k = j - h	**Kept/(Paid) by Company**	**$ 30,000**	**$115,000**	**$(55,000)**
l = (k + g) / 2	**Expected Kept/(Paid) by Company (Note)**	**$ -**	**$85,000**	**$(85,000)**
Note: Expected amounts based on equal probability of **Outcome 1** and **Outcome 2** occurring.				

Case 1 illustrates that if the FAC Fuel Costs used for the Base Cost factors is equal to the FAC Fuel Costs in the revenue requirement used for setting general rates, the utility does not over or under-collect as a result of the level of actual energy costs. The FAC works as it is intended to.

Case 2 illustrates that if the FAC Fuel Costs used for the Base Cost Factors is less than the FAC Fuel Costs in the revenue requirement used for setting general rates, the utility would collect more than was intended and customers pay more than the FAC was designed for them to pay regardless of the level of actual of energy costs.

Case 3 illustrates that if the FAC Fuel Costs used for the Base Cost Factors is greater than the FAC Fuel Costs in the revenue requirement used for setting general rates, the utility will not collect all of the costs that was intended in the FAC design and customers are expected to not pay the entire amount intended in the design of the FAC regardless of the level of actual energy costs.

These three cases illustrate the importance of setting the Base Cost factors in the FAC correctly, i.e., rebasing the Base Cost factors to match with the FAC Fuel Costs in the revenue requirement used for setting general rates.

Another important reason to rebase the Base Cost factors to match the FAC Fuel Costs in the revenue requirement used for setting general rates is the recent changes in Empire's supply-side resources. Empire's purchased power contract for power from the Jeffrey Energy Center expired May 2010, the coal-fired Plum Point power plant was deemed in-service in August 13, 2010, and Staff has recommended that the Commission approve an in-service date for Iatan 2 of August 26, 2010. While the contract for power from Jeffery Energy Center was for low-cost base load energy, both the Plum Point and the Iatan 2 plants are expected to have lower fuel costs than the Jeffery Energy Center. With these changes in Empire's supply-side resources alone, the FAC Fuel Cost in Staff's true-up revenue requirement will change from the FAC Fuel Cost in Staff's direct case revenue requirement. As mentioned earlier, setting the Base Cost factors in the FAC using the FAC Fuel Cost that is in the revenue requirement used for setting general rates will ensure a well-functioning FAC and FAC sharing mechanism. Therefore, Staff recommends that the Base Cost factors in Empire's FAC be reset in this case to match with the FAC Fuel Cost in the revenue requirement upon which the Commission sets general rates in this case.

F. Empire's Integrated Resource Plan

On September 3, 2010, as required by the Commission's Chapter 22 Electric Utility Resource Planning rules, Empire filed in File No. EO-2011-0066 its documentation of its resource planning process and its preferred resource plan. Staff filed a report regarding its review of Empire's filing on January 3, 2011. Staff found Empire's filing in compliance with the rules except for certain Demand Side Management (DSM) aspects. Staff is currently working with Empire and other parties to the IRP case to resolve the DSM issues. The parties in that case expect to file a stipulation and agreement with the Commission that will resolve all the parties' alleged deficiencies, shortly after this report is filed. As a part of Empire's resource planning process, the Company has selected a preferred resource plan after performing a Risk Analysis and Strategy Selection process.

G. Recommended Changes to the FAC

Staff recommends the following changes be made to Empire's FAC. Staff will provide exemplar FAC tariff sheets to reflect these changes as part of its Class Cost-of-Service and Rate Design testimony on March 16, 2011:

1. Change the sharing mechanism in Empire's FAC from 95%/5% to 85%/15%;

2. Include language to reset the Base Cost factors in Empire's FAC to equal the FAC Fuel Costs in the revenue requirement used for setting general rates in this and each succeeding general rate case by changing the first line of the COSTS section of the FAC to read: "Base Cost factors in this FAC are calculated using the costs included in the revenue requirement upon which Empire's general rates are set for fuel, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control System consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowance revenues, and renewable energy credit revenues.;

Staff recommends the Commission order Empire to continue to provide the following information as part of its monthly reports as Empire agreed to do in the *Non-Unanimous Stipulation and Agreement* filed May 12, 2010 in ER-2010-0130:

1. Monthly Southwest Power Pool ("SPP") market settlements and revenue neutrality uplift charges;

2. Notify Staff within 30 days of entering a new long-term contract for transportation, coal, natural gas or other fuel; natural gas spot transactions are specifically excluded;

3. Provide Staff with a monthly natural gas fuel report that includes all transactions, spot and longer term; the report will include term, volumes, price and analysis of number of bids;

> 4. Notify Staff within 30 days of any material change in Empire's fuel hedging policy, and provide the Staff with access to new written policy;
>
> 5. Provide Staff its Missouri Fuel Adjustment Interest calculation workpapers in electronic format with all formulas intact when Empire files for a change in the cost adjustment factor;
>
> 6. Notify Staff within 30 days of any change in Empire's internal policies for participating in the SPP;
>
> 7. Continue to provide Staff access to all contracts and policies upon Staff's request, at Empire's corporate office in Joplin, Missouri.

Staff Expert/Witness: Matt J. Barnes

H. Fuel Adjustment Clause Heat Rate and Efficiency Testing

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

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

Since the Commission authorized Empire's FAC in its *Report and Order* in Case No. ER-2008-0093, effective August 9, 2008, Empire is required by 4 CSR 240-3.161(3)(Q) to file supporting results of its heat rate testing when it files to continue or modify its fuel adjustment clause.

Empire filed the results of their heat rate testing with their work papers in this case, and the Staff reviewed the results of those tests. The test results and associated data appear to be reasonable. There are now base line heat rate testing results for all of Empire's generating plants to which future heat rate test results can be compared as a measure of the change of efficiency of the plant.

Staff Expert/Witness: Leon Bender

Appendices:

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation

Appendix 3: Alphabetical Listing of Testimony Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Shana Atkinson

Shana Atkinson

Subscribed and sworn to before me this 23rd day of February, 2011.

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

D Suzie Mankin

Notary Public

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AFFIDAVIT OF 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 as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

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AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Alan J Bax

Alan J. Bax

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AFFIDAVIT OF LEON C. BENDER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Leon C Bender

Leon C. Bender

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Walt Cecil

Walt Cecil

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith D. Foster

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Paul R. Harrison

Paul R. Harrison

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D Suzie Mankin

Notary Public

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AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Charles R. Hyneman

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AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Hojong Kang

Hojong Kang

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D. Suzie Mankin

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AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Shawn E Lange
Shawn E. Lange

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AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Erin L. Maloney

Erin L. Maloney

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AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Amanda C. McMellen

Amanda C. McMellen

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Mark L. Oligschlaeger

Mark L.Oligschlaeger

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AFFIDAVIT OF JOHN A. ROBINETT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

John A. Robinett

John A. Robinett

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AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

John A Rogers

John A. Rogers

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AFFIDAVIT OF HENRY E. WARREN, PhD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Henry E. Warren

Henry E. Warren, PhD

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AFFIDAVIT OF CURT WELLS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Curt Wells

Curt Wells

Subscribed and sworn to before me this 23rd day of February, 2011.

D. Suzie Mankin

Notary Public

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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 as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Casey Westhues

Casey Westhues

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AFFIDAVIT OF SEOUNG JOUN WON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Seoung Joun Won

Seoung Joun Won

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