MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

Revenue Requirement

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2012-0345

Jefferson City, Missouri
November 30, 2012

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

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COST OF SERVICE REPORT

THE EMPIRE DISTRICT ELECTRIC COMPANY
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COST OF SERVICE REPORT

I. Executive Summary

The Staff ("Staff") of the Missouri Public Service Commission ("Commission" or "PSC") has conducted a review in Case No. ER-2012-0345 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 permanent retail rates by approximately $30.7 million, exclusive of applicable gross receipts, sales, franchise or occupational fees or taxes, filed on July 6, 2012. Empire also filed a request for an interim rate increase, which the Commission has rejected.

The Staff's revenue requirement audit of Empire is based upon a **test year** of the twelve months ending March 30, 2012. Staff is using an **update period** ending June 30, 2012. Major elements of the revenue requirement calculation for Empire were measured through June 30, 2012, in Staff's case. Staff's audit results for Empire at the high end of its return on equity range (ROE) of 9.50% would be a rate increase of $13,817,579.

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

The impact of Staff's recommended revenue requirement for each retail rate customer class will be proposed in Staff's class cost of service and rate design testimony that is to be filed on December 13, 2012.

A. Major Issues

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

Return on Equity (ROE) – Staff has recommended a 9.5% ROE at the high end. Empire is requesting a 10.6% ROE. This issued is addressed in detail in the Section V of this Report.

Depreciation - The Company requested an overall increase in Empire's authorized depreciation rates. Empire also seeks an amortization of an alleged depreciation reserve deficiency associated with the planned retirement of its Riverton 7 and 8 generating units. Staff has recommended changes in Empire's current authorized rates, but is not recommending any accelerated depreciation or amortizations concerning the Riverton generating units. Staff has also made adjustments to the depreciation reserve to stopped depreciation, sale proceeds (salvage) and less income/expense from the Asbury unit train.

Transmission Expense – Staff has calculated Empire's transmission expense based upon the most current 12 months of historical transmission expenses incurred by Empire and any known and measureable increases to be charged to Empire by the Southwest Power Pool (SPP). Empire is requesting additional transmission expense based upon projected increases in the SPP transmission rates.

Ice Storm Amortizations – Staff has not included any of the ice storm amortizations in its direct case. The January 2007 ice storm was fully amortized as of January 2012 and the December 2007 ice storm will be fully amortized as of December 31, 2012.

There are various other issues between 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.

B. Regulatory Trackers

The following are tracking mechanisms which the Company requests creating, continuing, or ending in its direct filing. While the trackers do not have an immediate direct effect on the revenue requirement, they may impact future rate cases and future revenue requirements. A brief explanation of each item follows:

Vegetation Management Tracker – Empire requests to use 2013 budget figures in setting base rates to recover vegetation management expenses, and Empire also requests to end its current vegetation management tracker. Empire requests that if the Commission does not use the budgeted expenses for vegetation management to set rates, that the tracker for this item continue. Because the vegetation management costs do not appear to have stabilized yet, Staff recommends continuing the tracker and using actual vegetation management expenditures as the base in this proceeding.

SPP Transmission Tracker – Empire is requesting use of a tracker for its Southwest Power Pool (SPP) transmission expenses, which it asserts are expected to rapidly increase in the future. Staff has not included a SPP Transmission tracker in its direct recommendation.

Iatan and Plum Point O&M Tracker – Empire requests to continue the expense trackers for the Iatan and Plum Point O&M expenses since the units are new and there has been little operating history to determine ongoing expense levels. Staff agrees with the Company that the tracker should continue.

Pension and OPEBS Tracker – Staff recommends continuation of the pension and OPEB trackers that were reauthorized in Empire's previous rate case, Case No. ER-2011-0004.

C. Use of Budgeted or Projected Expenses

Empire's direct filing included many expenses and rate base items that were calculated based on budgeted or projected information, instead of relying on test year or normalized levels. Staff's case does not include any budgeted or projected information, because it is not known and measurable. Staff recommends true-up of several rate base and expense items in this case as of December 31, 2012. Staff's true-up recommendation is addressed in Section III of this report. The following is a list of items of some of the items in which the Company has used budgeted information in its direct case while Staff has used known and measureable information in this direct filing:

Plant
Accumulated Depreciation Reserve
Accumulated Deferred Income Tax
Fuel and Purchased Power Expense
Healthcare Expense
SPP Transmission Expense
Pension and OPEB Expense
Vegetation Management Expense
DSM Program Expense
ERP Maintenance Expense
O & M Expense
Property Tax Expense
Rate Case Expense

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 June 30, 2012, Empire served approximately 167,213 retail electric customers throughout its system of which approximately 148,323 are Missouri customers.

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

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

Empire last sought to change its Missouri jurisdictional electric retail rates in Case No. ER-2011-0004. Through its Order dated June 1, 2011 in that proceeding, the Commission granted Empire a total net increase in rates of $18,685,000.

On October 1, 2012, Empire filed an application to Modify its Fuel Adjustment Clause (FAC) rates. The Commission issued an order on November 15, 2012, approving the new rates to be effective December 1, 2012. Staff has rebased the FAC as a part of this case although the FAC rates will not reset to zero until the next Cost Adjustment Factor case following the effective dates of rates in this case. The change in rates for Empire recommended in the Staff's direct filing in this proceeding is based on the most recent available fuel information, which includes $8,640,992 currently being collected pursuant to Empire's FAC.

III. Test Year/Update Period/True-Up

The purpose of an update period is to establish a cut-off point to which major elements of a utility's revenue requirement are to be updated, beyond the test year, for inclusion in Staff's and other parties' direct cases. In contrast, a true-up is a re-audit and update of major elements of a utility's revenue requirement beyond the end of the ordered test year and update period. When ordered, true-ups involve the filing of additional set of testimony and the scheduling of additional evidentiary hearings ordered by the Commission.

Empire filed its case based upon a March 31, 2012, test year. The Commission ordered a test year based upon twelve months ending March 31, 2012, with an update period to reflect known and measureable changes through June 30, 2012. The Commission also ordered a true-up period through December 31, 2012.

For purposes of the true-up audit, Staff will update through December 31, 2012 the following items: plant in service; depreciation reserve, other rate base components; payroll expense; payroll-related benefits; fuel and purchased power costs; depreciation and amortization expense; rate case expense; property taxes; related income tax effects; the customer growth annualization for revenues, SPP transmission revenues and expenses, and rate of return/cost of capital.

Staff Expert/Witness: Kimberly K. Bolin, Sections I, II, and III

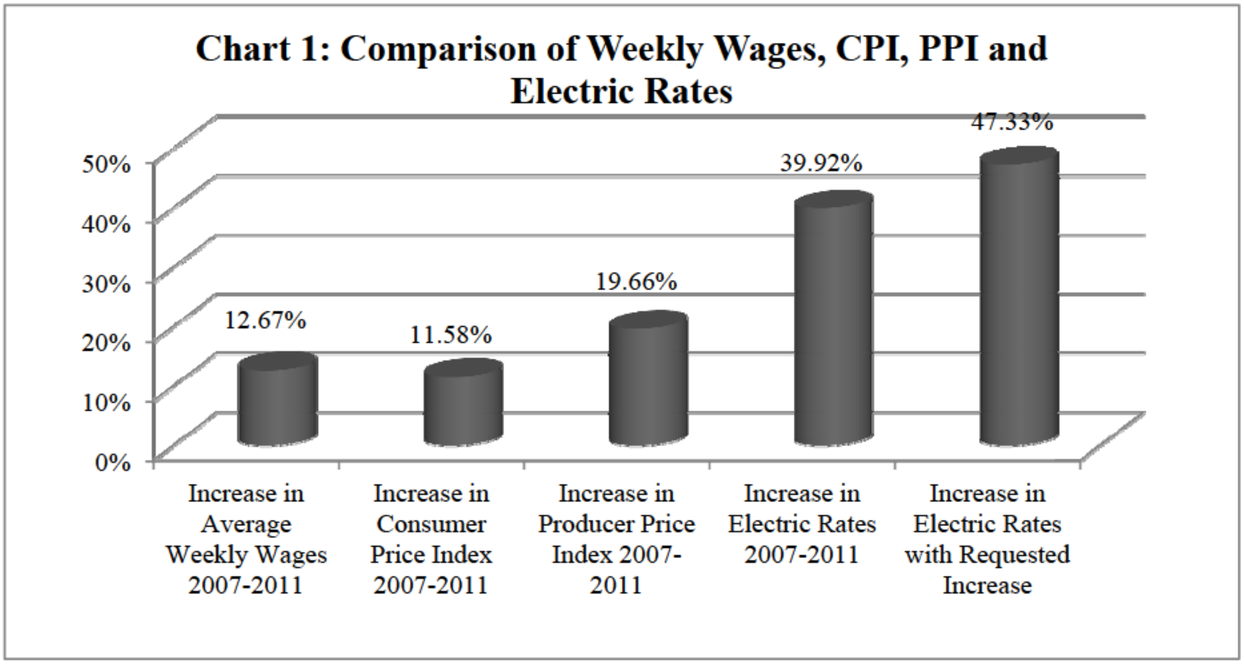
IV. Economic Considerations

As described below, Missouri and specifically the counties[1] in the Empire service area have experienced challenging economic times since 2007 due to the recession and a slow recovery. Chart 1 provides a comparison of the increase in average weekly wages, Consumer Price Index ("CPI"), Producer Price Index ("PPI") [2] and electric rates for counties within Empire's Missouri service area.

Continued on next page

[1] According to the minimum fling requirements submitted to the Commission, Empire serves 16 counties in Missouri: Barry, Barton, Cedar, Christian, Dade, Dallas, Greene, Hickory, Jasper, Lawrence, McDonald, Newton, Polk, St. Clair, Stone and Taney Counties.

[2] The Producer Price Index for Industrial Commodities includes: textile products and apparel, hides, skins, leather and related products, fuels and related products and power, chemicals and allied products, rubber and plastic products, lumber and wood products, pulp, paper and allied products, metals and metal products, machinery and equipment, furniture and household durables, nonmetallic mineral products and transportation equipment.



Empire's service area includes counties in Kansas, Arkansas, Oklahoma, and Missouri, with approximately 89% of the electric customers residing in Missouri.[3] The data compiled in Chart 1 - Chart 9 and in Table 1 and 2 only include the Missouri counties of Empire's service area.

From 2007 to 2011 the counties in Empire's Missouri service area experienced a 12.67% increase in average weekly wages. This increase was slightly higher than the overall Missouri compounded increase in average weekly wages of 11.63%. During that same time period the Consumer Price Index ("CPI") increased 11.58% in the Missouri counties served by Empire; while Empire's electric rates increased 39.92%. These rate increases accumulated to a total revenue increase of approximately $117 million for Empire, shown in Table 1.

Continued on next page

[3] Source: Direct Testimony of Company witness Brad Beecher.

Table 1: Empire Rate Case History 2007-2011

Case Number	Effective Date	Dollar Value	Percent Change
ER-2006-0315	December 14, 2007	$29,300,000	9.96%
ER-2008-0093	August 23, 2008	$22,040,395	6.70%
ER-2010-0130	September 10, 2010	$46,800,000	13.90%
ER-2011-0004	June 15, 2011	$18,685,000	4.70%
Total Dollars		$116,825,395	
Total Compounded Increase			39.92%

During this same time, however, purchasers of industrial commodities, such as Empire, have also experienced inflationary pressure, illustrated by an average 19.66% increase in the PPI for Industrial Commodities from 2007 to 2011.[4]

Based on an update period ended June 2012, trued-up through December 31, 2012, Empire is currently requesting an increase of $22.1 million in their revenue requirement which amounts to an additional 5.3% increase over current rates, after normalizing for revenues collected pursuant to Empire's Fuel Adjustment Clause (FAC).[5]

The increase in average weekly wages for counties in the Empire service area is less than one-half of the increase in electric rates from 2007-2011 and less than one-third of the increase in rates if the Company received its requested 5.3%. Although average weekly wages are increasing the cost of living as reflected by the CPI is increasing, decreasing the positive impact of the increase in average weekly wages.

Furthermore, in the second quarter of 2012 the cost of living utility index[6] for Missouri was 103.12. This indicates that general utility expenses constitute a higher percentage of a

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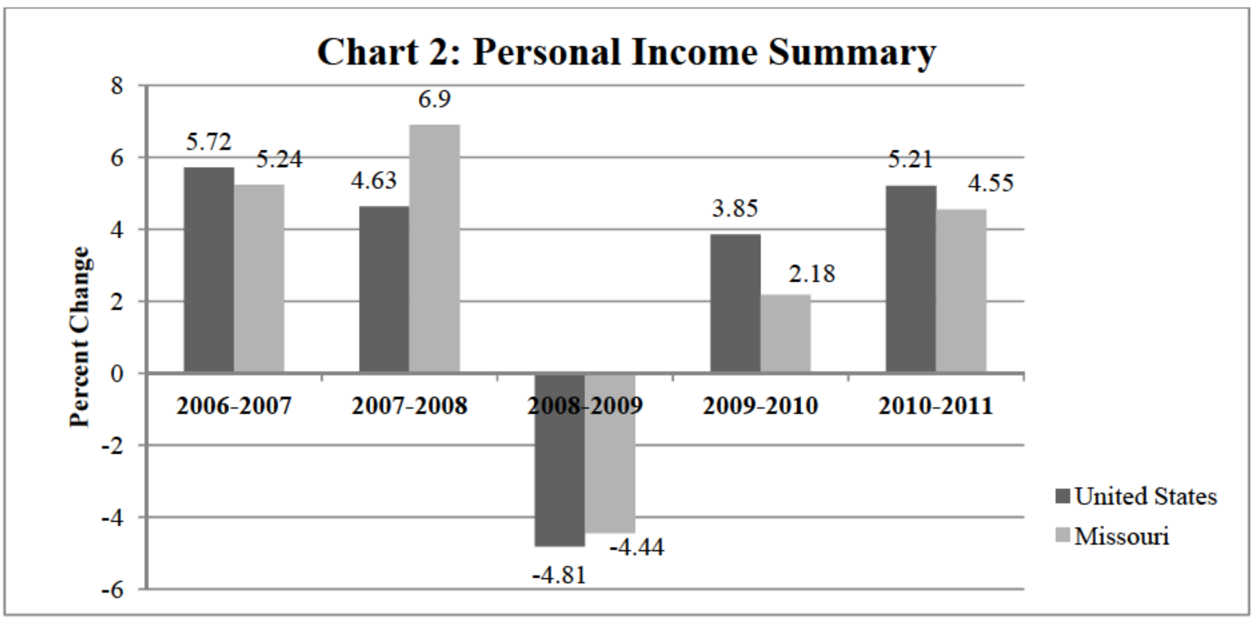
[4] Detailed information on Empire's expenditures and revenues can be found later in the Staff's Cost-of-Service Report.

[5] Per Company witness Kelly Walters direct testimony the overall requested increase is $30.7 million or a 7.6% increase, however, after the FAC is normalized the net increase is 22.1 million or a 5.3% increase in rates.

[6] Source: Missouri Economic Research and Information Center ("MERIC") and The Council for Community & Economic Research – 2nd Quarter 2012. The cost of living composite index represents indices for grocery items, housing, utilities, transportation, health care and misc. services. The utility index includes electric, natural gas and telephone services.

Missouri resident's living expenses than the average U.S. resident. The U.S. average is an average of the participating urban areas in that quarter and is the "base" value set at 100 for comparison. The Springfield, MO and Joplin, MO Metropolitan Statistical Areas ("MSAs")[7] are strikingly different with a cost of living utility index of 88.79 and 118.37 respectively. The difference between the two MSAs could be explained by the base rates of the utility used to set the index value, which is the utility that has 70% of the market or the two utilities that have the largest market share.[8] For example, the Springfield, MO MSA is served by Empire as well as the City of Springfield utilities; whereas the Joplin, MO MSA is only two counties and largely served by Empire.

According to the Current Economic Conditions in the Eighth Federal Reserve District report from the Federal Reserve Bank of St. Louis,[9] Missouri's economic recovery has been slower compared to the nation in personal income and economic activity. Chart 2 illustrates this through a comparison of personal income between the United States and Missouri, based on data obtained from the Bureau of Economic Analysis.



[7] The Joplin, MO MSA consists of Jasper and Newton Counties and the Springfield, MO MSA consists of Christian, Dallas, Greene, Polk and Webster Counties. Webster County is not in the Empire's Missouri service area.

[8] Source: ACCRA Cost of Living Index Manual, Published by the Council for Community and Economic Research (C2ER)

[9] The Federal Reserve Bank of St. Louis' Current Economic Conditions in the Eighth Federal Reserve District; June, 2012 and September, 2012 report included state and national level data as well as MSA level data for the St. Louis area. The only information used from the report was the national and state comparisons.

This data shows that between 2010 and 2011, Missouri experienced a percentage change of positive 4.55% in personal income, while the nation experienced a percentage change of positive 5.21%.

The Federal Reserve Bank of St. Louis, using data from the Federal Reserve Bank of Philadelphia, also reported that Missouri's coincident index,[10] as of June 2012, is at 94.4% of its pre-recession level where the nation is at 101.2% of its pre-recession level. Missouri's lowest level of economic activity was reported at 91.9% of pre-recession levels while the U.S. only dropped to 95.3% of its pre-recession level. As of September 2012, Missouri is still below its previous peak of economic activity which occurred in December 2007. Missouri also fell behind the nation in Gross Domestic Product[11] ("GDP") growth in 2010 and 2011, illustrated in Chart 3.

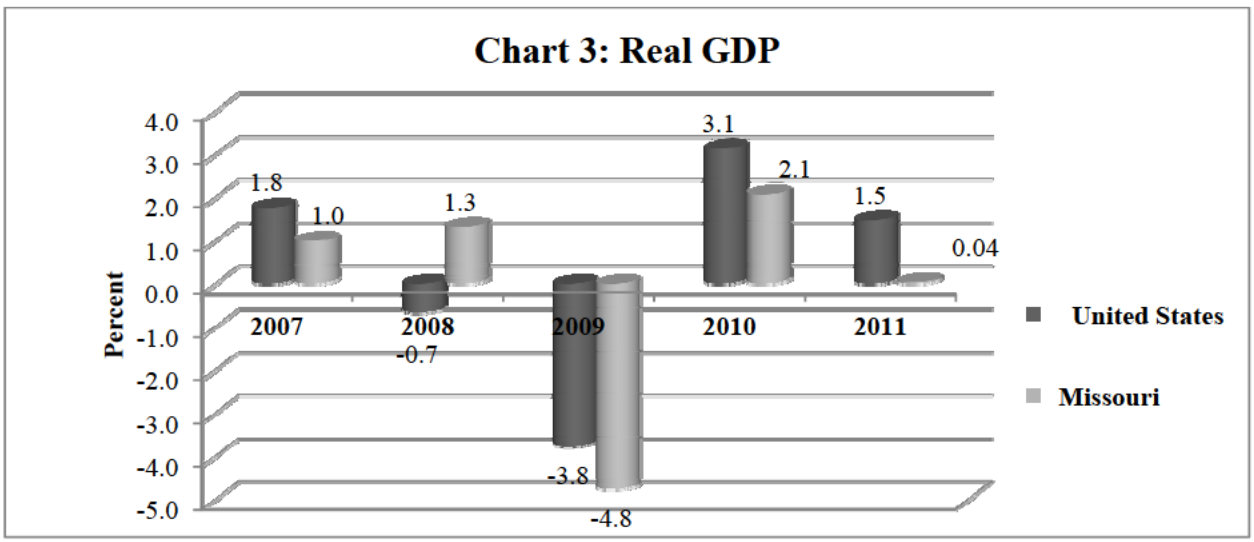


Chart 3, shows that Missouri's real GDP[12] only increased 0.04% in 2011, while that of the nation grew 1.5% in 2011 compared to the previous year. In 2010, Missouri's real GDP grew less than the nation's real GDP of 2.1% and 3.1%, respectfully. Growth in real GDP occurred in 2010 after Missouri's real GDP declined by 4.8% in 2009, compared to the nation's real GDP

[10] The Federal Reserve Bank of Philadelphia's coincident index is a combination of payroll employment, nominal wages and salaries, unemployment rate and average hours worked in the manufacturing sector to give a single measure of economic performance.

[11] Source: Bureau of Economic Analysis ("BEA")

[12] Advance 2011 real GDP by State statistics and revised 1997-2010 statistics were released on June 5th, 2012 by the Bureau of Economic Analysis.

decline of 3.8%. The personal income data, the coincident index data and the real GDP data suggests that Missouri is experiencing a slower recovery than the nation.

As explained below, the Missouri residents and businesses in the Empire service area are recovering from the longest and worst recession since the Great Depression[13] on lower than the national average weekly wage and lower than the national average per capita personal income. Communities in Empire's four-state service area are relatively small, as described by Company witness Brad Beecher, with only 29 of the 121 incorporated communities having more than 1,500 people and 10 communities with a population over 5,000 people. Joplin, Missouri is the largest city in the service area with a population of approximately 49,000. [14] In May of 2011, Joplin was hit by an F-5 tornado that destroyed many homes and businesses in and around Joplin. However, since the tornado approximately two-thirds of the 7,500 homes that were damaged have received building permits, 420 of 530 businesses that were damaged have reopened, 28 businesses have indicated they will reopen and 28 new businesses have opened. Lastly, 1,181 housing units are planning to be completed by early spring 2013.[15]

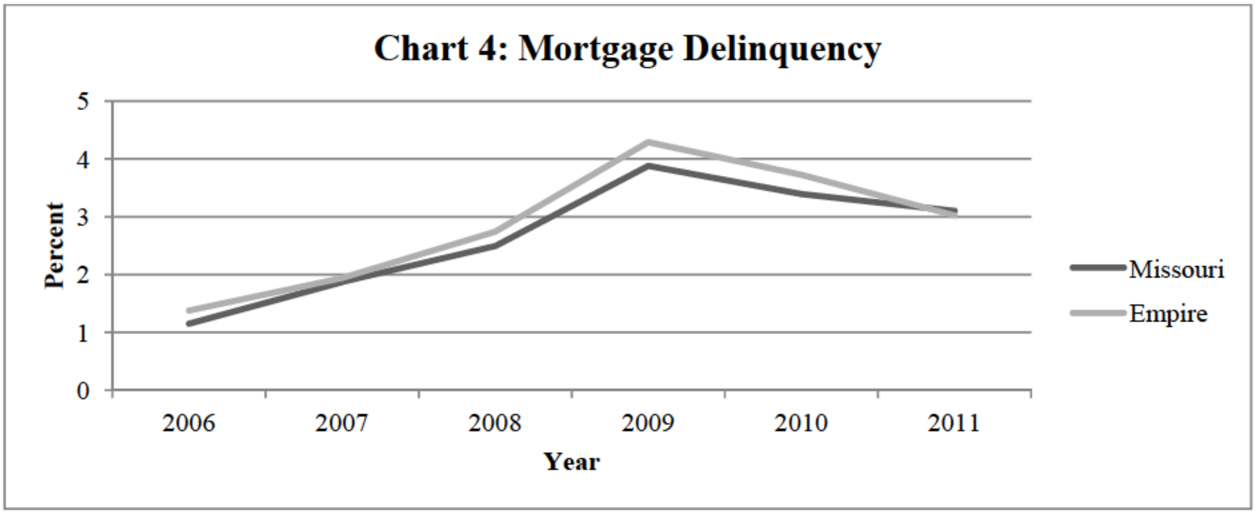
Depending on when data is collected and released from the Bureau of Labor Statistics and the Bureau of Economic Analysis, the information described below may not show the impact of the May 2011 tornado. For example, the counties in Empire's Missouri service area, on average, peaked in 2009 with a higher percentage of mortgage debt delinquency than the state average, as shown in Chart 4.

Continued on next page

[13] The Economic Report of the President, Chapter 1, Federal Reserve Bank of St. Louis.

[14] Source: Direct Testimony of Company witness Brad Beecher.

[15] Source: Interim Rebuttal Testimony of Staff witness Shawn E. Lange



The percentage of mortgage debt delinquency in the Missouri counties of Empire's service area decreased slightly below the Missouri average in 2011, which may be due to the tornado, but it is difficult to determine the exact cause of the decrease. The values in Chart 4 can be interpreted as the percent of mortgage debt balance that is 90+ days delinquent.[16] Of the counties[17] in Empire's Missouri service area, McDonald County had the highest percent of mortgage debt balance 90+ days delinquent at 4.99% in the fourth quarter of 2011 followed by Taney County at 4.77%. Newton County reported the lowest percent of mortgage delinquency at 1.96%.

The counties in Empire's Missouri service area experienced a lower unemployment rate[18] than the nation and the state in 2008, 2009, 2010 and 2011, shown in Chart 5.

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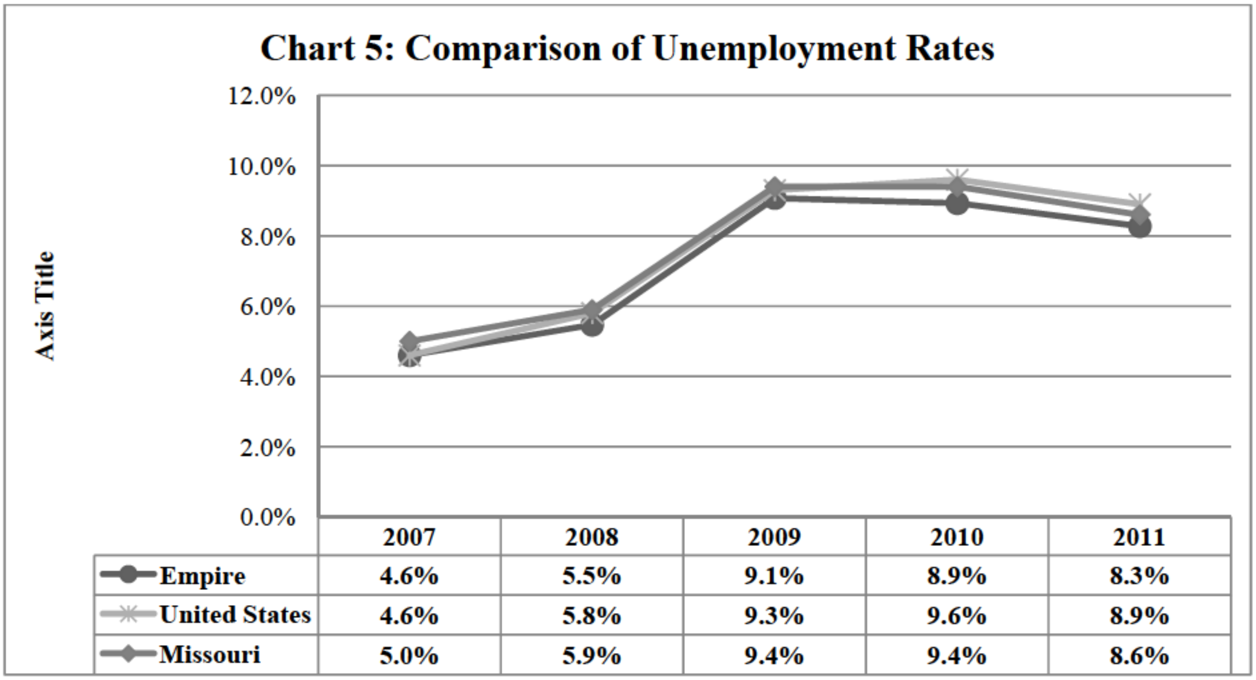
[16] Source: Federal Reserve Bank of New York, Consumer Credit Panel, 90+ days delinquent is considered seriously delinquent and in the foreclosure process.

[17] The Federal Reserve Bank of New York – Consumer Credit Panel, "only includes counties with an estimated population of at least 10,000 consumers with credit reports in the 4th quarter 2011." This includes 77 of the 115 counties in Missouri and 12 of 16 counties in the Empire service area.

[18] Source: Bureau of Labor Statistics, Local Area Unemployment Statistics.



Although the unemployment rate seems to be decreasing in 2011 for the Empire service area, as a whole, all of the counties that Empire serves in Missouri had higher unemployment rates in 2011 than in pre-recession 2007. Currently, in September of 2012 the unemployment rates have decreased to 6.9% for Missouri, 7.8% for the U.S. and, as a whole, the counties in Empire's Missouri service area had an unemployment rate of 5.6%.[19]

Chart 6, illustrates median household income based on data from the Missouri Economic Research and Information Center ("MERIC").

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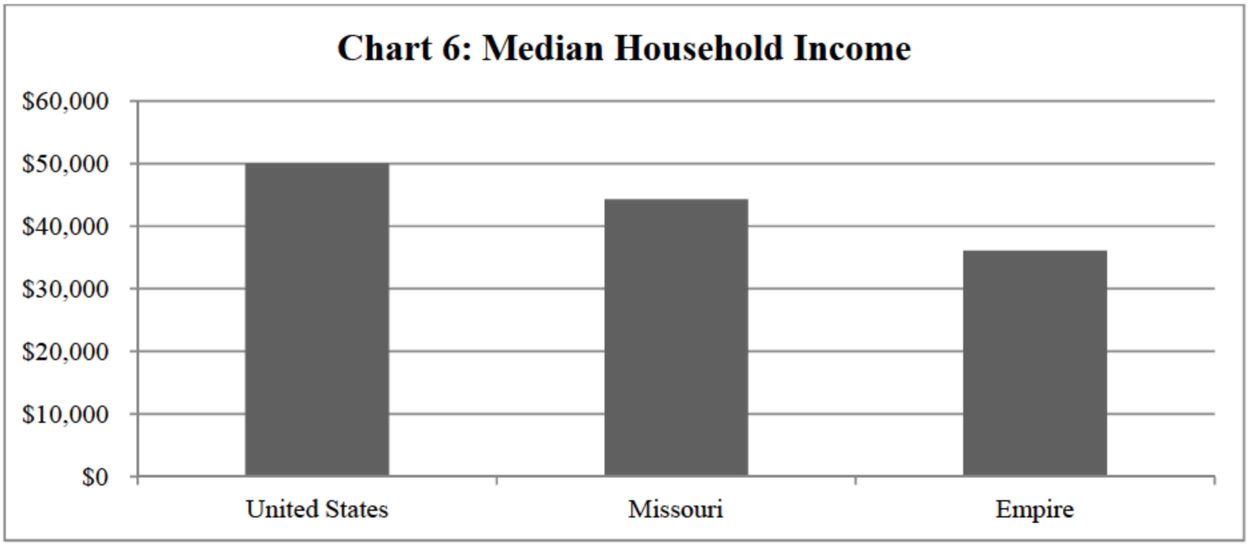
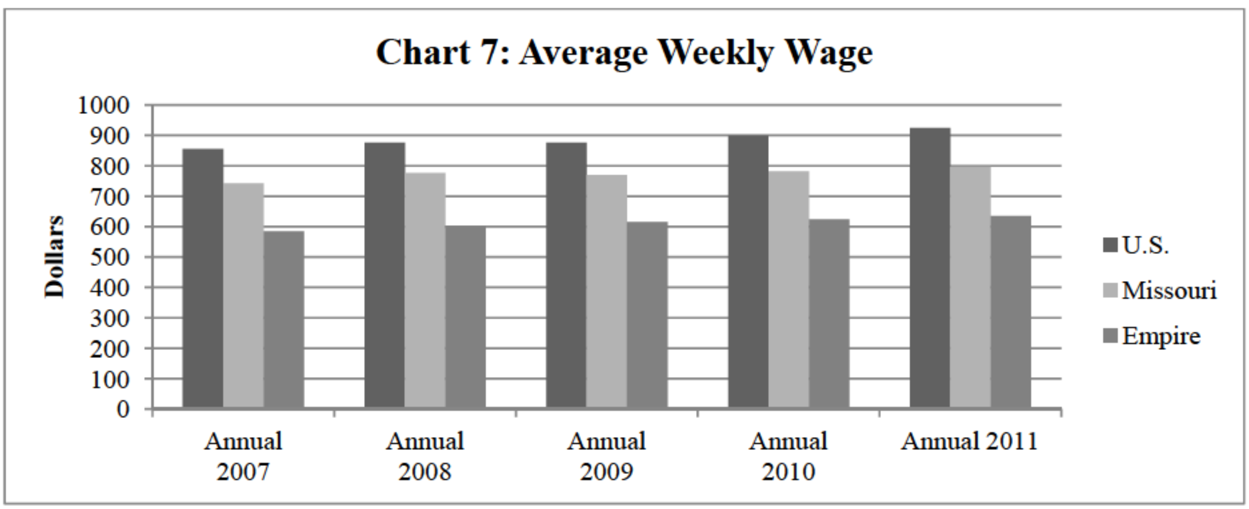
[19] Unemployment rates for September 2012 are still preliminary and will probably be revised as more information becomes available.



On average, the counties in Empire's Missouri service area fell below the national and state median household income levels in 2010.[20] The average weekly wage[21] for the counties in Empire's Missouri service area also fell below the national and state averages, shown in Chart 7.



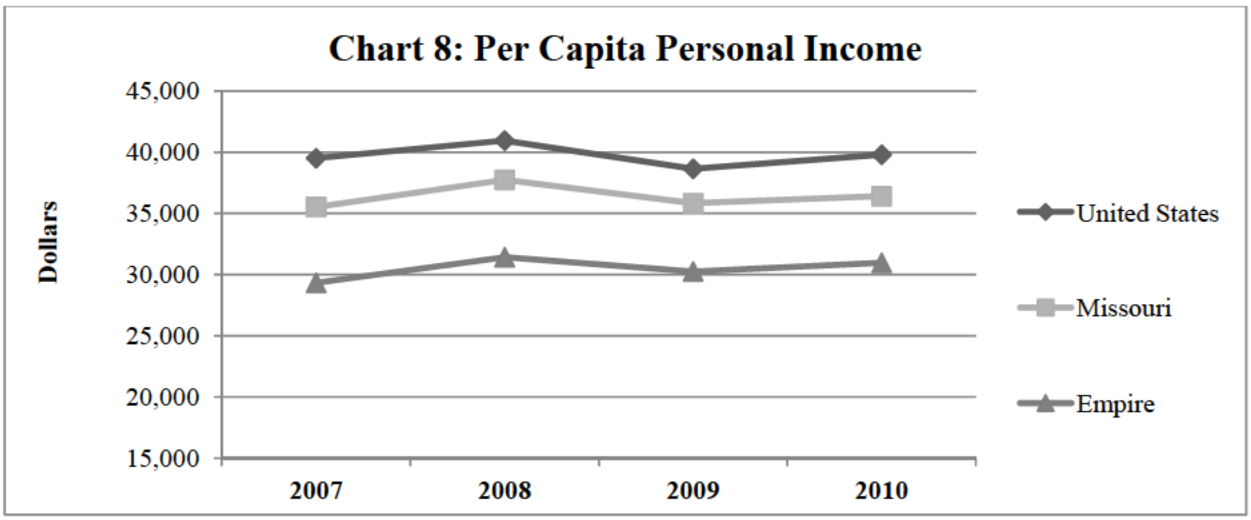
In 2011, all of the sixteen counties served by Empire in Missouri were below the national and state average weekly wages of $924 and $797, respectfully. The highest average weekly wage of the counties in Empire's Missouri service area was $690 reported for Greene County, approximately $234 less than the national average weekly wage. The median average weekly

[20] New median household income estimates will be released in December 2012.

[21] Source: Bureau of Labor Statistics: Quarterly Census of Employment and Wages, Average Weekly Wage 2007-2011. Per Bureau of Labor Statistics, "annual average weekly wage values are calculated by dividing total annual wages by the average of the twelve monthly employment levels and dividing the result by fifty-two."

wage in 2011, for the counties in Empire's Missouri service area was $518. This can be interpreted as the average weekly wage in 50% of the counties in Empire's Missouri service area was below $518, and 50% was above. Again, it is important to note that the communities in Empire's Missouri service area are fairly small, and although Empire serves Greene County they do not serve the City of Springfield or the southeast corner of the county. According to the U.S. Census Bureau, the City of Springfield, alone, has approximately 160,000 people.

In 2010, the per capita personal income[22&23] level for the counties served by Empire in Missouri was $30,962, which is approximately 18% lower than the state average of $36,406 and 28% lower than the national per capita personal income level of $39,791, shown in Chart 8.



Among the counties in Empire's Missouri service area, Greene County reported the highest per capita personal income level of $35,362, but it is still lower than the state and national averages. In 2011, Missouri reported a per capita personal income level of $37,969 which fell below the national per capita personal income level of $41,560. However, this was the first time the state and the nation experienced a per capita personal income level that surpassed the 2008 levels by approximately 1% and 1.5%, respectfully.

Although, the counties in Empire's Missouri service area experience a lower unemployment rate than Missouri and the nation, they also earn below average per capita

[22] Source: Bureau of Economic Analysis, Local Area Personal Income data for 2011 will not be available until November 26th, 2012.

[23] Per capita personal income is calculated as total personal income divided by total midyear population.

personal income and average weekly wages. Using data from the Energy Information Administration (EIA), in 2011 a Missouri residential customer served by Empire pays more per kWh, than other residential customers supplied by investor owned utilities in Missouri, shown in Table 2.

Table 2: Average Retail Price Comparisons 2011

		All Sectors	Residential	Commercial	Industrial	Transportation
Entity	**State**	**Average Retail Price (cents/kWh)**	**Average Retail Price (cents/kWh)**	**Average Retail Price (cents/kWh)**	**Average Retail Price (cents/kWh)**	**Average Retail Price (cents/kWh)**
Empire District Electric Co	MO	10.11	11.29	10.05	7.73	
KCP&L Greater Missouri Operations Co.	MO	8.84	10.39	8.21	6.13	
Kansas City Power & Light Co	MO	8.67	10.52	8.39	6.28	
Union Electric Co - (MO)	MO	7.51	9.17	7.39	5.04	6.90
Missouri		8.32	9.75	8.04	5.85	6.90
United States		9.90	11.72	10.23	6.82	10.46

In addition, Empire's cents per kWh for all sectors is 10.11¢ and is actually higher than the national average of 9.90 cents per kWh. It is important to note that average cents per kWh is calculated by taking total revenues[24] divided by total consumption or kWh and it does not represent a specific tariffed rate.

Staff Expert/Witness: Robin Kliethermes

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 ("COE")

[24] Total revenues may include customer charges, demand charges, energy charges and energy efficiency charges.

must be determined through expert analysis. Staff's expert financial analyst, Shana Atkinson, has estimated Empire's COE by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff then considered the COE, net of any risk adjustments, together with other capital component information as of June 30, 2012, to develop its recommended ROR for Empire, as follows:

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.50%**	**9.00%**	**9.50%**
Common Stock Equity	51.06%	-----	4.34%	4.59%	4.85%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	48.94%	5.91%	2.89%	2.89%	2.89%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
Total	**100.00%**		**7.23%**	**7.49%**	**7.74%**

As contained in the above table, Staff recommends, based upon its expert analysis, a return on common equity ("ROE") range of 8.50% to 9.50%, mid-point 9.00%, and an overall ROR of 7.23% to 7.74%, mid-point 7.49%. Staff recommends that the Commission authorize a ROE of 9.50% based on the high-end of its recommended ROE range due to past concerns about Staff's estimates being too low. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-24. Staff's workpapers will be provided to the parties at the time of filing Staff's Cost of Service Report. Staff will make any source documents of specific interest available upon the request of any party to this case or 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 ROR in two frequently-cited cases.[25] In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:[26]

> 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:[27]

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

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

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

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[25] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943); *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923)

[26] 262 U.S. 679, 692-693, 43 S. Ct. 675, 679, 67 L.Ed. 1176.

[27] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

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

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[28] 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;[29] 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 COE 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 COE for Empire.

In this case, Staff has applied this comparable company approach through the use of both the DCF and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's COE. 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* ROE based on the COE is consistent with the principles set

[28] Neither the Discounted Cash Flow ("DCF") nor the Capital Asset Pricing Model ("CAPM") methods were in use when those decisions were issued.

[29] 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.*

forth in ***Hope*** and ***Bluefield***. However, as Staff will discuss extensively throughout this section of the report, Staff believes its recommended ROE in this case is higher than Empire's COE.

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 COE should pass the "common sense" test when considering the broader current economic and capital market conditions.

1. Economic Conditions

The United States economy has been growing at a tepid pace since the most severe recession since the Great Depression. The pattern of this slow economic recovery has been much different than other past recoveries from severe recessions, in which the economy usually grew at a fairly rapid pace for a few years following the recession. This has investors, policy makers and academics concerned about the long-term prospects for not only U.S. growth, but for that of global economic growth. Most economists project domestic growth 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%.[30] 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). In June 2012 the Fed extended Operation Twist, in which the Fed is purchasing $45 billion a month of long-term Treasury bonds. In September 2012 the Fed launched a program to buy $40 billion a month of mortgage backed securities. In the Fed's October 2012 meeting the Fed announced it would continue these programs, as well as keep short term interest rates near zero through at least mid-2015.

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[30] The Congressional Budget Office (CBO), *An Update to The Budget and Economic Outlook: Fiscal Years 2012-2022,* August 2012; Minutes from the Federal Open Market Committee's ("FOMC") meeting on September 12-13, 2012; Third Quarter 2012 Survey of Professional Forecasters; Energy Information Administration's 2012 Annual Energy Outlook; and The Livingston Survey, June 7, 2012.

According to a *WSJ* article the Fed repeated their concern with economic growth and the labor market in their meeting in October 2012:[31]

> The Federal Reserve held its easy-money policies steady in its final meeting before the presidential election and made few changes to its assessment of an economic recovery which it has found frustratingly anemic.
>
> 'The Committee remains concerned that, without sufficient policy accommodation, economic growth might not be strong enough to generate sustained improvement in labor market conditions,' it said in the statement.
>
> Barring a clear pickup in employment or inflation, the Fed has signaled that it is inclined to keep buying bonds on a large scale. The Fed statement Wednesday said it would continue purchasing mortgage and other bonds 'if the outlook for the labor market does not improve substantially."

As of September 2012, the Fed projected the economy would grow between 1.7% and 2.0% this year and between 2.5% and 3% next year. The Fed also raised its inflation estimates to 1.7% to 1.8% for this year from its previous projection of 1.2% to 1.7% as of June 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 a lack of sustainable growth in the economy. Although there is also discussion of the possible impact monetary policy may have on inflation in the future, the market is not factoring in a high expected inflation rate in security prices. The 2012 monthly spread between 30-year Treasury Inflation Protected Securities ("TIPS") and non-inflation protected Treasury bonds implies investors are requiring an additional 2.20% to 2.50% return for potential inflation.[32] The low spread of 2.20% was in the months of June and July 2012 and the high spread of 2.50% was in October 2012.

2. Capital Market Conditions

a. Utility Debt Markets

Debt markets have been very attractive for utility companies in recent months. It has started to become fairly common for utilities to issue 10-year to 15-year bonds at coupons in the

[31] Jon Hilsenrath and Kristina Peterson, "The Fed Holds Steady, Points to Weak Recovery," *Wall Street Journal*, October 25, 2012, p. A4.

[32] http://research.stlouisfed.org/fred2/categories/22

3% range. Empire issued $88 million of 15-year secured debt at a coupon of 3.58% in April 2012. If one were to assume that the risk premium[33] required to invest in utility stocks rather than utility bonds was constant, then these lower utility debt yields clearly translate into a lower required ROE. In other words, a lower cost of debt is indicative of a lower cost of capital, all else equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Although long-term interest rates, as measured by 30-year Treasury bonds ("T-bonds"), increased to the 4% range during the November 2010 to July 2011 period, they have since decreased to the high 2% to 3% range for the period August 2011 through October 2012, reaching a low of 2.59% in July 2012. (*see* Schedules 4-2 and 4-3).

Long-term utility bond yields have also continued to more closely track the changes in the 30-year T-bond yields in the aftermath of the financial crisis of late 2008 and early 2009. Although the current spread between utility bond yields and 30-year Treasury yields is slightly above the average of 1.55% since 1980 (1.87%), the absolute yield on utility bonds recently fell below 5% for the first time during this prolonged period of low interest rates and slow economic growth. (*see* Schedules 4-1 and 4-3).

b. Utility Equity Markets

For the nine months ended September 30, 2012, the total return on the Dow Jones Industrial Average ("DJIA") was 10.0%, the total return on the Standard & Poor's 500 ("S&P 500") was 16.4%, and the total return on the Edison Electric Institute ("EEI") Index of electric utilities was 4.7% (*see* Appendix 2, Attachment B). More specifically on a non-market capitalization weighted basis, the total return for the nine months ended September 30, 2012 was 6.4% for EEI "Regulated" electric utilities, 6.5% for EEI "Mostly Regulated" electric utilities and 4.0% for "Diversified" electric utilities.

The relative performance of electric utility stocks to that of the broader markets for recent months has been more typical in that they have lagged the broader market indices. However, this was not the case for 2010 and 2011. According to EEI, "Regulated" electric utilities' total returns in 2010 were 15.8%. Adding the "Regulated" utilities' returns for 2011 with those achieved in 2010, totals 38.1% over the last two years, a truly spectacular couple of years for

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

electric utility stock returns. This compares to total returns of 22.5% and 17.2% for the DJIA and the S&P 500 for the same period. It appears that these strong returns have been driven largely by the continued decline in bond yields over the past year. This is highly consistent with investors' views that utility stocks compete with bond investments because they are largely considered to be bond surrogates/substitutes. In order for equilibrium to return to bond prices as they relate to utility stock prices, either bond prices would decrease (bond yields increase) and/or utility stock prices would increase. So far, it has been the latter. The increase in utility stock price valuations does not appear to be driven by higher growth expectations for the regulated utility sector. Staff's proxy group in this case contains eight companies Staff used in the last Empire rate case. The average forward price-to-earnings ("p/e") ratio for these eight companies increased from 13.36x to 15.34x in just a little over a year and a half. Electric utility stocks p/e ratios tend to be influenced by a few primary factors, such as expected growth in earnings, dividend payout ratios and the COE. In the current capital market environment, it appears that a declining COE is the primary driver of higher p/e ratios because the projected 5-year earnings-per-share ("EPS") forecasted growth rates have actually declined since the last rate case. Staff believes capital market data clearly supports its position that the COE has declined since the last Empire rate case. Another indication of the continued decrease in the cost of capital, especially for regulated electric utilities, is the fact that the electric utility industry is trading at a premium, i.e. higher p/e ratios, to that of the S&P 500. During a recent Society of Utility and Regulatory Analysts ("SURFA") conference Staff attended on April 26 and 27, 2012, Greg Gordon, CFA, Senior Managing Director and Partner with International Strategy and Investment, provided a presentation showing that regulated electric utilities' p/e ratios have been approximately 1.2x higher than that of the S&P 500. According to the following commentary provided by Value Line, the premium valuation levels for electric utilities continues to exist:

> Electric utility issues usually trade at a below-market price-earnings ratio, unless earnings are depressed. (*ITC Holdings* is an exception.) However, several utilities are now trading at a price-earnings ratio that is above the market's. This is an indication of how expensively priced many of these equities have become. Another indication of their high valuation is the fact that many of them are trading within their 2015-2017 Target Price Range.[34]

[34] Value Line Investment Survey September 21, 2012 Ratings Report on the Central Region of the Electric Utility Industry.

Higher p/e ratios are usually associated with higher growth companies. In the aggregate, the projected growth in EPS over the next 5-years for the S&P 500 is typically 10% or higher, whereas utilities' 5-year EPS growth forecasts are typically in the 5% to 6% range. If investors are paying a premium for electric utility stocks, it is because of the low comparative returns offered by bonds, not the prospect for growth higher than that of the market. Utility stock returns are consistently highly correlated with bond returns. The current macroeconomic environment is clearly favorable to utilities in terms of a lower cost of capital for debt and equity instruments. Staff believes these lower capital costs should be shared with ratepayers through lower authorized ROEs.

In a recent Barron's 2012 Roundtable discussion, Bill Gross, founder and managing director of PIMCO indicated the following about utility returns:

> They pay big dividends because they continually are granted a 10% return on equity by regulators in a world where returns are moving much lower. After earning 10% they can pay out 4% to 5% to investors.[35]

Consequently, it appears the capital market environment not only continues to support the ability to authorize ROEs below 10%, but it seems as if it expects them to be lowered considering the current capital and economic environment.

D. Empire's Operations

The following excerpt from Empire's Form 10-K filing with the Securities and Exchange Commission ("SEC") for the 2011 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.

[35] Lauren R. Rublin, "Listen Up, Class: Here's How to Profit," *Barron's Cover, January 16, 2012,* p. 11, http://online.barrons.com/article/SB50001424052748703535904577152932179268296 html#articleTabs_article%3D0

Our gross operating revenues in 2011 were derived as follows:

Electric segment sales*	90.9%
Gas segment sales	8.0
Other segment sales	1.1

*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. As of December 31, 2011, our electric operations served approximately 166,500 customers.

Our retail electric revenues for 2011 by jurisdiction were derived as follows:

Missouri	88.8%
Kansas	5.3
Arkansas	2.8
Oklahoma	3.1

We supply electric service at retail to 120 incorporated communities as of December 31, 2011, 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 50% of our electric operating revenues in 2011 were derived from incorporated communities with franchises having at least ten years remaining and approximately 20% 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 2011 were derived as follows:

Residential	42.4%
Commercial	30.1
Industrial	15.1
Wholesale on-system	3.7
Wholesale off-system	4.5
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 2011 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2011.
>
> Our gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2011, our gas operations served approximately 44,000 customers. We provide natural gas distribution to 45 communities and 315 transportation customers as of December 31, 2011. 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 provisions, since our acquisition, we have obtained renewals of all our expiring gas franchises prior to the expiration dates.
>
> Our gas operating revenues in 2011 were derived as follows:

Residential	62.5%
Commercial	26.9
Industrial	1.5
Other	9.1

> No single retail customer accounted for more than 1% of gas revenues in 2011.
>
> Our other segment consists of our fiber optics business. As of December 31, 2011, we have 97 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-'.[36] 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.

[36] Empire's 2011 SEC Form 10-K filing for the year ended December 31, 2011, p. 16.

The following is an excerpt from a March 23, 2012, S&P credit-rating report on Empire:

> Standard & Poor's Ratings Services' ratings on Joplin, Mo.-based utility Empire District Electric Co. reflect an "excellent" business risk profile and an "aggressive" financial risk profile (as our criteria define the terms).
>
> Although Empire is relatively small, its business risk profile is "excellent" given a diverse service territory with limited cyclical industrial concentration (approximately 15% of its total retail load), a straightforward integrated utility business model, and a cost-conscious management team. These characteristics are tempered by a historically challenging regulatory environment in Missouri, which we view as less credit supportive than those in other states. However, the Missouri Public Service Commission (MPSC) appears to be becoming more responsive to the company's rate needs, as demonstrated by approval of settlement agreements and implementation of a fuel-adjustment clause that allows the company to recover 95% of changes in fuel and purchased-power costs in a timely manner.
>
> We believe Empire's financial measures will remain at levels suitable for current ratings--even when capital spending peaks in 2015—because of potential additional rate relief, continuation of a fuel-adjustment mechanism in Missouri and the other jurisdictions in which Empire operates, and credit-supportive actions by management, including future common stock issuances.

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 COE.

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 June 30, 2012, 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 51.06 percent common equity and 48.94 percent long-term debt.

Staff should also note that the recommended ratemaking capital structure does not contain short-term debt. This is not because Empire does not issue short-term debt for purposes of funding its operations. Staff did not include Empire's short-term debt in the capital structure because for the twelve months ending June 30, 2012, Empire's average Construction Work in Progress ("CWIP") balance exceeded its short-term debt balance.

2. Embedded Cost of Debt

Staff's embedded cost of long-term debt of 5.91 percent is based on information provided by Empire in response to Staff Data Request No. 0152. 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 $1,883,571 associated with Empire's $2.5 million of debt expenses incurred to amend its mortgage bond indenture in order to provide additional flexibility to pay its dividend. Staff subtracted this amount from Empire's cost of debt calculation for the period ending June 30, 2012. Staff has consistently proposed this disallowance in Empire's past rate cases as well. Staff provides the underlying details of its embedded cost of debt estimate in Schedule 6.

3. Cost of Common Equity

Staff estimated Empire's COE through a comparable company COE analysis of a proxy group of 11 companies using the DCF method. However, because Staff's 11-company proxy group included all but one of the companies Staff used in the recent Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), Kansas City Power & Light Company ("KCPL") and KCP&L Greater Missouri Operations ("GMO") rate cases, Case Nos. ER-2012-0166, ER-2012-0174 and ER-2012-0175, in order to evaluate relative changes in implied COE estimates since these cases, Staff will also provide data on the same 10-company proxy group used in those cases. 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 53 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) Staff decided to add one additional criterion in this case as compared to Empire's last rate case. Staff added a criterion to screen out companies that do not have an equivalent S&P business risk profile as Empire, which is currently 'Excellent.' Staff believes it was important to add this criterion to further screen utility companies that may have non-regulated operations that are impacting the parent company's business risk even though they were classified as "regulated" by EEI. For example, although EEI classifies Ameren Corporation ("Ameren") as a "regulated" electric utility, many investment analysts, such as Goldman Sachs, consider Ameren to be a diversified company. Staff's criteria are as follows:

1. Classified as an electric utility company by Value Line (53 companies);
2. Publicly-traded stock;
3. Followed by EEI and classified as a regulated electric utility (19 companies eliminated, 36 remaining);
4. Followed by AUS and reporting at least 70% of revenues from electric operations (12 companies eliminated, 24 remaining);
5. Ten years of Value Line historical growth data available (3 companies eliminated, 21 remaining);
6. No reduced dividend since 2009 (2 companies eliminated, 19 remaining);
7. Projected growth available from Value Line and Reuters (0 companies eliminated, 19 remaining);
8. At least investment grade credit rating (2 companies eliminated, 17 remaining);
9. Rated an 'Excellent' Business Risk Profile by S&P (4 companies eliminated, 13 remaining);
10. Company-owned generating assets (1 company eliminated, 12 remaining); and
11. Significant merger or acquisition announced in last 3 years (1 company eliminated, 11 remaining).

This resulted in a proxy group of 11 publicly-traded electric utility companies ("the comparables"). The comparables are listed on Appendix 2, Schedule 9. Staff's proxy group includes one company, PNM Resources, which was not included in the most recent Ameren Missouri, KCPL and GMO rate cases. In order to evaluate the relative change in the COE since those cases, Staff will also provide information using the same proxy group that was used in those recent cases.

b. The Constant-growth DCF

Next, Staff estimated Empire's COE 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.[37] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing a weighted average of the 2012 and 2013 Value Line projected dividend per share (*see* Schedule 12) by the monthly high/low average stock price for the three months ending October 31, 2012 (*see* Schedule 11).[38] Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the eleven comparable companies is approximately 3.90%, unadjusted for quarterly compounding. The projected average dividend yield for the comparable companies excluding PNM Resources, unadjusted for quarterly compounding is approximately 4.00%.

i. The Inputs

In the DCF method, the COE 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

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

[38] 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.

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.[39] 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 found a very wide dispersion in projected EPS growth (2.00% to 16.00%). PNM Resources accounts for the extremely high projected 5-year EPS growth rate of 16.00%. Excluding this growth rate, the spread is much smaller (2.00% to 6.50%). Equity analysts' earnings estimates provided on *Reuters.com* also showed a wide dispersion of 3.00% to 9.04%. This same spread of earnings estimates is 3.00% to 8.90% if PNM Resources is excluded. The average projected 5-year EPS annual compound growth rate estimates yielded a growth rate of 6.00%. Excluding PNM Resources, the average projected 5-year EPS annual compound growth rate estimates yielded a lower growth rate of 5.35%. (*see* Schedule 10-4, Column 6).

Due to the current volatility and wide dispersions present in Staff's analysis of historical and projected DPS, EPS, and BVPS, Staff only gave this data limited weight in estimating a reasonable growth rate for it single-stage DCF analysis. For reasons Staff will discuss in more detail below, use of equity analysts' forecasts of 5-year EPS growth is not reasonable in the context of estimating the COE using a single-stage DCF methodology. However, if Staff uses rates consistent with these estimates in its constant-growth DCF, the COE indication is approximately 8.90% to 9.90%. Excluding PNM Resources its constant growth DCF estimates a COE of 8.40% to 9.40%. If Staff had used the same growth rates for the same companies it used in the Ameren Missouri, KCPL and GMO rate cases, the implied COE would have been approximately 9.50%, which is below the 9.60% estimate Staff had provided in those cases. This implies there has been a slight decline in the COE for regulated electric utility companies since Staff performed its analysis in those previous cases.

Although use of equity analysts' 5-year EPS growth forecasts as a constant growth rate is easy and popular in utility ratemaking, investors do not assume their utility investments can grow at this rate into perpetuity when estimating a fair price to pay for utility stocks. For example,

[39] 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.

even though Staff included PNM Resources in its proxy group because it met Staff's criteria, it is completely irrational to assume investors believe their investment in PNM would grow in perpetuity at a rate of 12.52%. Not only does practical investment analysis prove this wrong, but empirical evidence proves that EPS growth for the electric utility industry has never achieved these lofty growth rates over a long period. This was true even during the growth stage of the electric utility industry.

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.[40] 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 rate[41], Staff decided its analysis of historical growth in the electric utility industry could only marginally support a more aggressive growth rate range of 5.0% to 6.0%. Staff emphasizes that it believes this growth rate is higher than what investors expect for the electric utility industry considering that it is higher than the expected long-term GDP growth of approximately 4.5%. Although there have been periods in which electric utility aggregate nominal growth has been higher than that of nominal GDP growth, this has not occurred for the last 20 years (*see* Schedule 13). On a per share basis, which is the focus of investors, electric utility growth has been much lower. Because a multi-stage DCF analysis allows the investors to address

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[40] 2003 Mergent *Public Utility & Transportation Manual*, p. a15-a18.

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

non-constant growth expectations, Staff places primary weight on its multi-stage DCF analysis in this case.

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 3.90% and a growth rate range of 5.0% to 6.0% -- a COE of 8.90% to 9.90% may be implied (*see* Schedule 12-1). Using the constant-growth DCF model and using inputs that exclude PNM Resources – a projected dividend yield of 4.00% and a growth rate range of 4.40% to 5.40% -- a COE of 8.40% to 9.40% may be implied (*see* Schedule 12-2).

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.[42] 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 COE for Empire.

A multi-stage DCF may use either two or three growth stages, depending on the situation being modeled. In any case, the last stage must use a sustainable rate as it is considered to last into perpetuity. In fact, in Staff's experience, most DCF analyses do not assume a growth rate much higher than the expected rate of inflation, currently 2.0% to 2.5%. The ability of a multi-stage DCF analysis to reliably estimate the COE is primarily driven by the analyst using a reasonable growth rate 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.[43]

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.[44] 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,

[42] 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.

[43] 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.

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

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 COE for the 11-company proxy group in the range of 7.66% to 8.42%, midpoint of 8.04% and it was in the range of 7.62% to 8.38%, midpoint of 8.00% when PNM Resources was excluded from the proxy group. Staff's multi-stage DCF COE estimates for the same proxy companies used in the Ameren Missouri, KCPL and GMO are approximately 20 basis points lower in Staff's updated analysis in this case.

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 analyses 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.

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 COE estimate.

COE estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. In past rate cases the Commission has rejected Staff's estimated perpetual growth rates of 3.00% to 4.00% as being too low. However, Staff believes its further research supports the reasonableness, if not aggressiveness, of these growth rates. Staff will first explain the methodology it used to determine that a 3.00% to 4.00% growth rate is a reasonable proxy for perpetual growth for its electric utility comparable group. Staff will then discuss the additional research it performed to conclude that it is not reasonable to assume electric utilities can grow at the same rate as nominal GDP in perpetuity.

The Financial Analysis Department has access to Value Line data on *Central* region electric utility companies dating back to 1968.[45] Although Staff has access to current electric utility financial data for all regions of the United States (*Central, East* and *West*), Staff's access to older data from the *East* and *West* regions is limited. Staff believes it is important to analyze electric utility industry financial data to at least the early 1970s since this was approximately the beginning of the last large construction cycle for the electric utility industry.[46] Because 1968 is consistent with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc., bankruptcy in December 2001.

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

[46] 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).

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 Schedules 15-1 through 15-4.

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

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

Because the *Central* region utility information includes data on Missouri's electric utilities, Staff analyzed the actual growth achieved by Missouri's major electric utility companies over the same period. The rolling average 10-year compound EPS, DPS, and BVPS growth rates for the companies that own electric utility assets in Missouri (Ameren, KCPL and Empire) for this same period (1968-1999) were lower: the rolling average 10-year compound EPS growth rate was 2.37%; the rolling 10-year compound DPS growth rate was 3.31%; the rolling 10-year compound BVPS growth rate was 2.19%; and the overall average for DPS, EPS and BVPS growth rates was 2.62%.

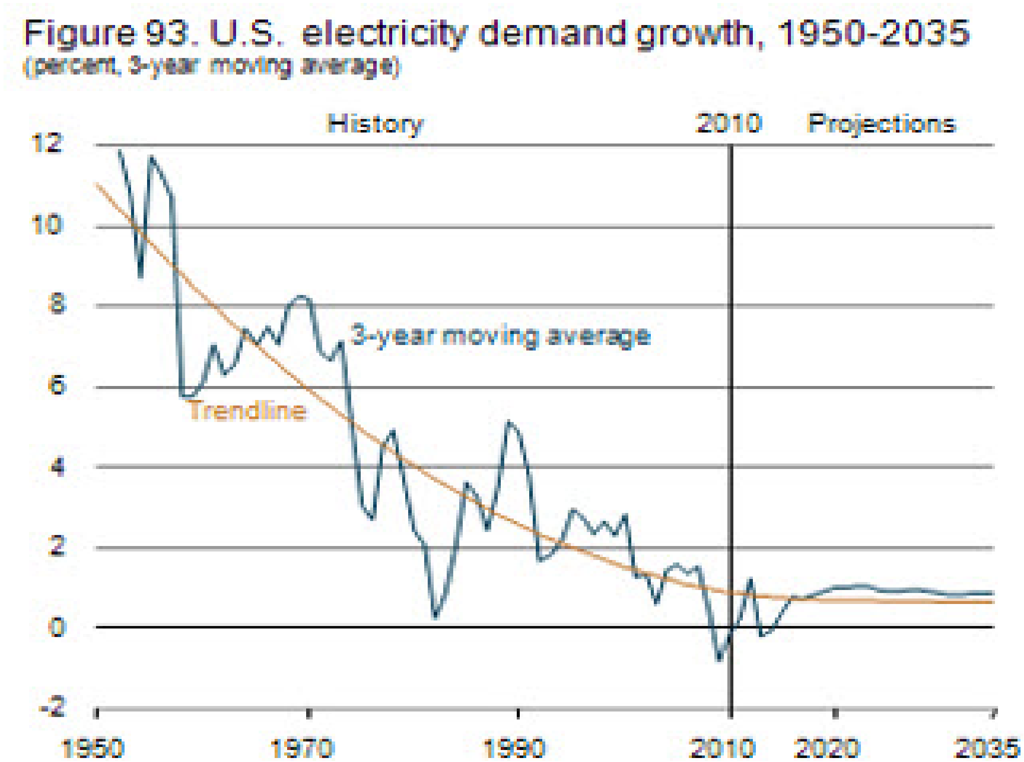
Because these three companies predominately operate in Missouri and have data available through the current period, Staff decided to evaluate the average 10-year rolling EPS, DPS and BVPS growth rate averages of these three companies from 1968 to 2011 and 1968 to 2008 in Schedule 15-5. Staff evaluated data through 2008 because this predated the financial crisis as well as each company's decision to reduce their DPS. The average 10-year rolling EPS, DPS and BVPS growth rate average decreased to 2.06% from 1968-2008 and 1.84% from 1968-2011. The graph in Schedule 15-6 clearly shows the steady decline in growth rates for the electric utility companies that own electric utility assets in Missouri. Only a foolish investor would turn a blind eye to such straight-forward data when developing growth expectations.

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 has had problems replicating this data, Staff believes this information is still useful in evaluating the trends in growth rates for the electric utility industry, which shows a downward trend in growth over the last 30 years. This data also demonstrates that electric utility companies' EPS and DPS do not grow at the same rate as GDP over the long-term.

v. Constraints on Long-term Growth Rates used in Stage Three

The Commission has dismissed Staff's use of a perpetual growth rate range of 3% to 4% in previous rate cases because they were too low and not supported by government an industry data. Although this is the case, Staff is using these same perpetual growth rates because, if anything, Staff believes its additional analysis and discovery of additional investment analysis proves that this growth rate range is higher than that used by investors in determining a fair price to pay for electric utility stocks.

Staff's support for its perpetual growth rate estimate was based in part on data analyzed for the period 1968 through 1999. Staff considers this period to be logical considering it captured the last building cycle in the electric utility industry, which started in the 1970s, peaked in the 1980s and fell through the 1990s. In fact, growth rates for this period would likely be considered higher than those expected in the future due to the fact that this period encapsulated a period of higher demand for electricity as illustrated in the following Energy Information Administration ("EIA") chart provided in its 2012 Annual Energy Outlook:



Source: Energy Information Administration's 2012 Annual Energy Outlook

To meet this load growth, electric utilities made significant investments in generating capacity in the late 70's and early 80's.

In attempt to address the Commission's previously stated concerns about the period and comparable group Staff used to analyze electric utility per share growth data, Staff researched a variety of freely-available, web-based sources to determine if information is available that would allow for a broader and more extensive evaluation of actual realized growth in at least the broader utilities sector (i.e. electric, natural gas and water), if not specifically the electric utility industry. However, this information is not freely-available. Access to this information would require subscriptions to sources, such as Compustat, Factset, KnowledgeReuters and Ned Davis Research, which are often utilized by institutional investors. If the Commission would like Staff to perform a more comprehensive analysis, then Staff would need to further research the best sources to which to subscribe in order to obtain access to the relevant information at a reasonable cost.

Various ROR witnesses, including customer ROR witnesses, assume electric utility companies can grow in perpetuity at the same rate as aggregate GDP. ROR witnesses may project GDP growth based on their own calculation of historical nominal GDP growth and/or they may consider projected long-term GDP growth rates from a variety of sources. Although Dr. Vander Weide's primary COE estimates do not incorporate GDP growth rates, Dr. Vander Weide does incorporate them in a multi-stage DCF analysis he provides because the Commission has recently shown a preference for this methodology. In Empire's last rate case, Dr. Vander Weide's multi-stage DCF analysis relied on EIA for his perpetual growth rate.[47] While there may be some logic for using projected GDP growth for the final stage for early to middle-stage companies, there is little logic for this approach for industries that are in the mature to declining stages of growth. Also, the use of nominal GDP growth does not take into consideration the fact that existing shareholders do not realize the aggregate growth of an industry due to the dilution caused by issuance of new equity.

Staff researched data provided by the Bureau of Economic Analysis ("BEA") on GDP growth by industry and by components. Although the use of projected aggregate GDP data is expedient and convenient, this comes at the expense of a reliable COE estimate. Staff does not believe investors would sacrifice reliability for expediency when making investment decisions. Several industries contribute to the aggregate GDP of the U.S. economy. Currently, the BEA compiles data based on the North American Industry Classification System of the United States ("NAICS"). Although the NAICS definitions include more refined utility classifications, the BEA only reports data for the aggregate Utilities definition, which is assigned NAICS Code 22. Although this is an aggregate codification, Staff believes investors would rely on data specific to the utilities sector rather than that of the aggregate economy when estimating the potential growth of their utility investments. Better yet, Staff believes investors would drill down into the detail of the contribution of utilities' profits to GDP rather than that of *total value added* to GDP.

According to Staff's analysis of the utilities industry data available since 1947, as illustrated below and in Schedule 17, the utilities industry made up less than 2% of GDP until the middle 1950s and then gradually increased to just shy of 3% of GDP in the 1980s and 1990s.

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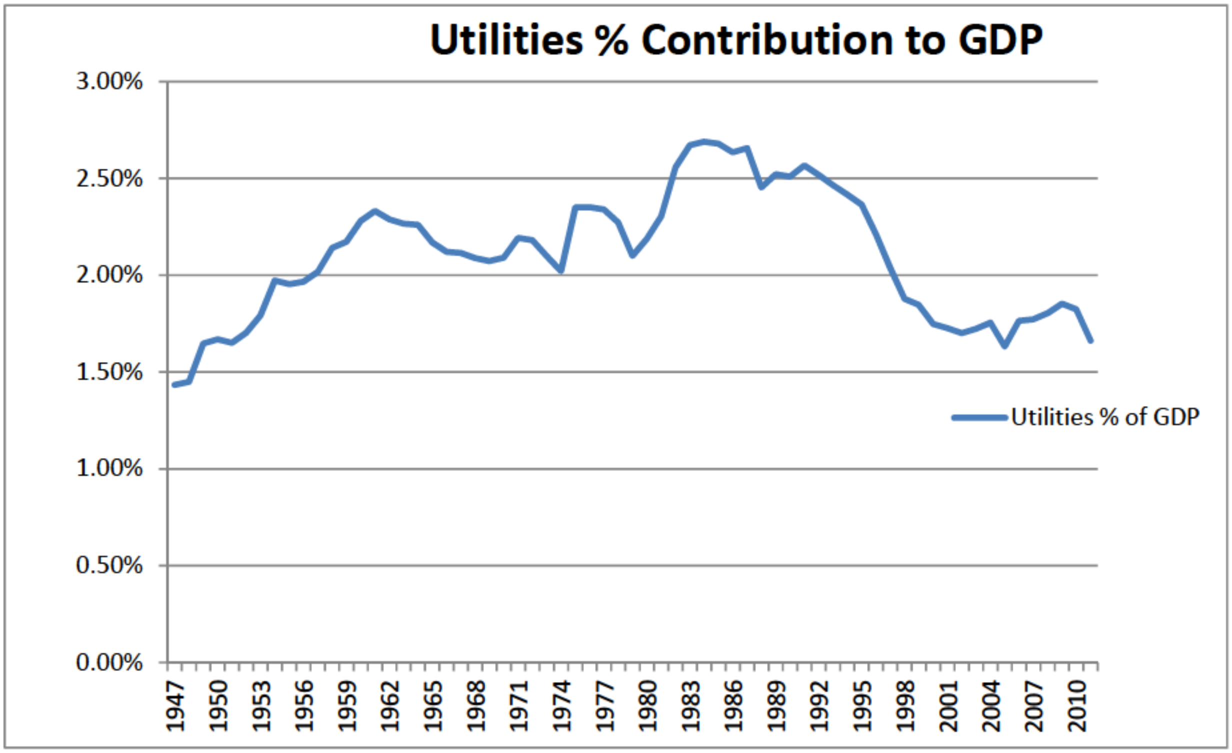
[47] In the current rate case Dr. Vander Weide used estimates of long-term GDP growth from the following sources: the long-term GDP growth forecast of EIA; long-run historical growth in real GDP based on data from the Bureau of Economic Analysis to the EIA's estimate of future inflation as measured by the GDP deflator; and historical growth in nominal GDP over the period 1929 through 2011 from the Bureau of Economic Analysis.

However, since the late 1990s, utilities contribution to GDP has declined to below 2% and has since leveled off.



Although it appears that utilities may contribute less to GDP going forward, if utilities continue to contribute the same percentage to GDP as they have for the last few years, then it is possible that the aggregate growth of *total value added* may be similar to that of aggregate GDP growth. It is extremely important to understand that this data represents *total value added* to GDP, not just aggregate earnings to shareholders or, more importantly, EPS and/or DPS, which is the primary focus of investors. Regardless, this data corroborates the data Staff provided in the last Empire rate case, which showed increases in EPS and DPS growth rates through the late 1980s and declining EPS and DPS growth rates from that point through at least 1999. Staff did not provide data for the period after 1999 because company-specific data lacked continuity due to restructurings, mergers and acquisitions and the Enron debacle. The GDP data for the period after 1999 shows the growth rate of at least *total value added* to GDP by utilities is not declining to the extent it had been for the previous decade. However, comparing the utility GDP growth since 1999 to the per share growth of companies with electric utility assets in Missouri further illustrates that per share growth is likely to be much lower than the growth of utilities' aggregate contribution to GDP growth. If utilities are to be able to stop this decline, they will need to determine how to add value to an economy that is not nearly as energy-intensive as it once was and is in fact looking at ways to cut back on energy use.

Staff also analyzed real GDP growth as compared to the utility industry's real growth for the period 1947 through 2011 (*see* Schedule 17). Staff's growth rate calculations are based on the same methodology Staff used to evaluate the long-term growth of the *Central* region electric utilities. For 10-year periods up to 1979, the utility industry's real growth rates were higher than that of GDP. However, the utility industry's 10-year real growth rates were much lower than real GDP 10-year growth rates during the 1980s. This is most likely due to the tremendous amount of capital invested in the electric utility industry during the building cycle that occurred during this period. Real utility growth grew at a higher rate than that of real GDP for a brief period through the early-to-mid 90s, but since this time the real growth rate of utilities has been lower than that of real GDP growth. This would seem to imply that the utility industry is possibly in a state of decline or at least in another building cycle. If the latter, then this may cause investors to project higher aggregate growth over the near-term, but because this construction cycle is not being driven by demand growth, it seems illogical that investors would expect a growth rate higher than that achieved during the last construction cycle.

The utility industry's contribution to GDP discussed above is based on the *value added,* both real and nominal, of the industry, which is the sum of <u>compensation to employees</u>, <u>taxes on production and imports</u> less <u>subsidies</u>, and <u>gross operating surplus</u>. Although utility corporate profits would seem to be the most relevant data for the purposes of evaluating utility growth, unfortunately, the BEA website does not provide this data for the aggregate utility industry for years prior to 1998. It should also be noted that the corporate profit figure is an aggregate figure, which does not consider the dilution caused by the issuance of new equity. However, the BEA website does provide this data for SIC code 49 for electric, gas and sanitary services. Although this code includes industries other than utilities, it is still more refined than that of aggregate corporate profits for all industries that contribute to GDP growth. As with utility industry's *total value added* contribution to GDP, corporate profits peaked in the 1980s and have since declined (*see* Schedule 20). Additionally, the growth rates in utility value added to GDP were also higher than electric utility industry per share growth rates, although not as much as the corporate profit growth rates. Because Staff analyzed a proxy group of Value Line *Central* region electric utilities over this same period, Staff decided to compare these per share growth rates to corporate profit growth and utility value added growth (*see* Schedule 21). These per share growth rates were much lower than the growth of corporate profits and utility value added. The fact that electric utilities had to issue equity to fund capital expenditures during this period probably explains the difference in these growth rates.

The issuance of additional equity creates a dilution of earnings to existing shareholders. Because the utility industry has historically had a high dividend payout ratio (DPS/EPS), anytime it needs to make large investments, it needs to issue new capital in the form of debt and equity. This can cause a vicious cycle for utility companies as described in *The Analysis and Use of Financial Statements,* 1998, by Gerald I. White, Ashwinpaul C. Sondhi and Dov Fried:

> Although this example may appear unrealistic, it is a reasonable description of the plight of public utility companies (gas, electric, water) in the United States. To attract investors, these firms historically paid out most of their earnings as dividends. To finance growth, they periodically sold additional common shares. As a result, EPS growth rates were low. These firms were trapped in a vicious cycle. If they reduced their dividend rates, their EPS growth rates would rise, and they might be considered growth companies rather than bond substitutes.

Staff's research regarding the relation of GDP growth to that of utility industry growth caused it to discover several journal articles that addressed GDP growth as it relates to EPS and DPS growth of the S&P 500. In past rate cases, Staff has provided academic and logical support that suggests that long-term nominal GDP growth may make sense as a proxy for perpetual growth for a broader index, such as the S&P 500. However, this assumption may even be too aggressive for purposes of estimating returns for the S&P 500.

William J. Bernstein and Robert D. Arnott published an article, "Earnings Growth: The Two Percent Dilution," in the September/October 2003 edition of the *Financial Analysts Journal.* This article reviewed some of the key drivers behind the bull market in the 1990s. One such driver was an apparent belief that earnings could grow faster than the macroeconomy. The authors contend that earnings must actually grow slower than that of the economy because growth of existing enterprises contribute only partly to GDP growth; the role of entrepreneurial capitalism, the creation of new enterprises, is a key driver of GDP growth, yet it does not contribute to earnings and dividend growth of existing enterprises. The other main factor the authors attributed to actual realized growth being less than that of aggregate GDP growth is that new equity issuances almost always exceed stock buybacks by an average of 2% or more a year.

A key observation made by the authors that lends support for the notion that at least aggregate corporate earnings may be able to grow at the same rate as GDP growth is that for the period 1929 through 2000, trend growth for corporate profits and nominal GDP was nearly identical. However, as the authors state, the ability of earnings and dividends to grow at this same rate is only possible if no new enterprises are created and no new shares in existing enterprises are issued. The authors illustrate that these two factors caused the growth in DPS over the period 1900-2000 to be 2.7% lower than real GDP growth in the United States and 2.3% lower than real GDP for relatively stable countries throughout the world. Consequently, empirical evidence shows that per share growth will be less than GDP growth even for the broader markets. The findings from the Bernstein and Arnott article were largely confirmed in another subsequent article, "Economic Growth and Equity Investing," by Bradford Cornell, published in the January/February 2010 edition of the *Financial Analysts Journal.* Cornell studied United States stock market data for the period 1926-2008. This information showed an average rate of dilution to aggregate growth of approximately 2%. The author specifically states: "Therefore, to estimate the growth rate of earnings to which current investors have a claim, approximately 2% must be deducted from the growth rate of aggregate earnings."

Although not addressed in these articles, another reason why broader markets may not grow at the same rate as U.S. GDP growth is because of the globalization of many companies that are domiciled in the United States. According to Ned Davis Research, 52.6% of pretax profits for companies in the S&P 500 came from outside the U.S.[48] Consequently, the profits of these global companies should also be dependent on the economic growth of the other countries in which they operate.

The above-mentioned articles address the relation of GDP growth to that of broader stock market growth expectations, not specifically to expected growth for utilities. In the August 2011 edition of *Public Utilities Fortnightly* ("PUF"), Steven Kihm addressed this issue more fully in an article, "Rethinking ROE: Rational estimates lead to reasonable valuations."[49] Kihm

[48] "A Smarter Way to Invest Globally? Maybe it's time for world-stock funds, rather than ones that focus separately on the U.S. and Overseas," Javier Espinoza, *The Wall Street Journal,* C5 and C8*,* June 4, 2012

[49] "Rethinking ROE: Rational estimates lead to reasonable valuations," Steven Kihm, *Public Utilities Fortnightly,* August 2011, pp. 16-21.

specifically addresses the recent common practice in utility rate cases of estimating the COE using the DCF and assuming that utility share prices can grow in perpetuity at the same rate of nominal GDP. Kihm specifically stated the following in regard to the interaction of GDP growth, DPS growth of the S&P 500, and DPS growth for the Moody's Electric Utility stock index:

> In the last half of the 20th century, nominal GDP grew about 8 percent per year. Dividends per share for the S&P 500 Index grew at only 6 percent per year. Dividends per share for Moody's Electric Utility stock index grew even more slowly at less than 4 percent per year. This suggests that utilities can be expected to grow not at the GDP growth rate, but at about half that rate on an annual basis.

Although Staff has drawn similar conclusions when analyzing long-term utility per share growth as compared to GDP growth, Staff notes that Kihm identified the same 2% dilution in S&P 500 DPS growth as discussed in the aforementioned financial literature. Staff verified this observation by analyzing data provided in the *Economic Report of the President (2012),* which provides earning and dividend information for the S&P 500 from 1947 through 2011. Schedule 21 clearly shows that actual realized EPS and DPS growth is less than that of nominal GDP. Again, considering the fact that, on average, companies in the S&P 500 retain far more earnings to pursue growth than utilities, no rational investor would expect utilities to grow in the long-term at a rate close to that of nominal GDP.

Kihm discusses one of the often-used explanations as to why GDP should be used as a proxy for long-term utility growth -- namely, that if utilities don't keep pace with economic growth, they will become a shrinking segment of the economy. Staff's analysis of the BEA data actually proves that this is in fact what has happened over the last 60 years. Over approximately the last 20 years, utilities' *total value added* as a percentage of GDP growth has been declining. Although it is hard to fathom that utilities will become obsolete, assuming utilities do not need to expand to meet additional load growth, it is logical to assume that utilities should not grow much faster than the rate of inflation in the long-term.[50] In the PUF article, Kihm also discusses the impact of dilution on expected growth rates for utilities by comparing Southern Company's

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[50] Kihm worked for more than 20 years as a member of the staff of the Public Service Commission of Wisconsin ("Wisconsin Commission"). He developed the staff's two-stage DCF model, which is still used by Wisconsin Commission staff. The Wisconsin Commission staff's DCF model uses the inflation rate for the perpetual growth rate for utilities.

aggregate dividend growth rate and Southern Company per share dividend growth rate to that of GDP growth for the period 1995 to 2010. Southern Company's annual compound growth rate for *aggregate* dividends was 4.2%, while the annual compound growth rate for nominal GDP was 4.6% for this same period. However, after taking into consideration the additional common equity Southern Company issued over this period, the annual dividend compound growth rate was only 2.6% on a per share basis. Clearly this empirical evidence disproves the assumption that utilities could grow anywhere near the rate of GDP growth over the long-term.

A simple example using the earnings retention method of estimating sustainable growth rates illustrates the fallacy of assuming that utility per share growth rates can approach the level of aggregate GDP growth. The S&P 500 has historically earned ROEs in the 10% to 15% range with an average close to 12.50%.[51] For purposes of this example, we will assume that the S&P 500 will earn a 12.50% ROE in the long-run. Assuming the S&P 500 dividend payout ratio remains near the average of approximately 40% for the past decade, then this translates into 60% of earnings retained for reinvestment. At an expected 12.5% ROE (mid-point of the 10% to 15% range), this translates into a potential growth rate of 7.5% for the S&P 500. Now, assuming electric utilities should be allowed to earn an ROE similar to that of the S&P 500, which would be too high in Staff's opinion, since electric utilities typically maintain a dividend payout ratio of approximately 65%, this allows for a potential growth rate of 4.375%. Consequently, simple mathematics dictates that because electric utilities have higher payout ratios than the S&P 500, even if they earn a similar ROE, their per share growth would have to be lower than the S&P 500. Considering that the allowed ROEs have been in the 10% to 10.25% range, assuming electric utilities continue to pay out 65% of their earnings in dividends, this would translate into a growth rate of approximately 3.5%.

It is worth emphasizing that the articles Staff has reviewed explore the relationship of GDP growth to EPS and DPS for the broader markets, such as the S&P 500. This is consistent with most mainstream financial literature that suggests expected nominal GDP growth can be used as a proxy for perpetual growth for a broad index. However, Staff is not aware of any such literature that suggests this is appropriate for a mature, low-growth sector such as that of utilities.

[51] Timothy Vick, "Picking Stocks The Buffett Way: Understanding Return on Equity," American Association of Individual Investors, April 2001; Frank K. Reilly, "The Impact of Inflation on ROE, Growth and Stock Prices," Financial Services Review, 1997.

In fact, Staff has provided evidence in past cases that investment analysts do not make this assumption when estimating a fair price to pay for utility stocks.

Kihm also provides an example of why current utility stock prices seem logical when using a more reasonable COE estimate. In Kihm's example, he uses an 8% COE to arrive at a price estimate of $50.62 for Consolidated Edison, which was within 4% of the stock price at the time (June 2011). Kihm's example can be taken one step further by performing a DCF valuation estimate using the same COE and the assumption that utility dividends per share can grow at the same rate as GDP in the long-term. Consolidated Edison's annual dividend in 2011 was $2.40. If one assumes that this dividend can grow in perpetuity at a compound annual rate of 5% and the COE is the same 8% used by Kihm, then this would translate into an intrinsic value of $84, 52% higher than its current trading price. However, if one assumes a much more reasonable dividend growth rate of approximately 3% with the same COE, then the intrinsic value of the stock would be $49.44, which is close to Kihm's estimate.

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.

vi. Preference for GDP Growth

Although Staff is confident that investors do not expect electric utilities' per share figures to grow at the same rate of nominal GDP in the long-run, Staff recognizes that even customer ROR witnesses have been willing to accept this assumption for purposes of estimating the COE. Consequently, Staff will provide a COE indication using this simplified approach.

Projected GDP growth is available from a variety of sources, such as the Congressional Budget Office ("CBO"), the Federal Reserve, the EIA, and Blue Chip Economic Forecasts. Staff will use the CBO, EIA, The Survey of Professional Forecasters published by the Philadelphia Federal Reserve, The Federal Open Market Committee ("FOMC"), and the Livingston Survey for purposes of long-term projected GDP growth. The CBO projects an annual compound growth rate in nominal GDP of approximately 4.80% for the period 2012 through 2022; EIA projects an annual compound growth rate of 4.45% for the period 2010 through 2035; The Survey of Professional Forecasters projects a 10-year annual compound growth rate in real GDP of 2.64%; The Livingston Survey projects an average annual compound growth rate of 2.70% over the next ten years and the FOMC projects a central tendency long-term real GDP growth of 2.30% to 2.50%. In each case in which the sources do not project a nominal GDP growth rate, Staff recommends applying a GDP price deflator of 2.0%, which is the CBO's prediction of long-term inflation and also the inflation rate which is targeted by the Federal Reserve. Based on these projections, the long-term nominal GDP growth rate is expected to be in the range of 4.30% to 4.80%. If the Commission chooses to use a GDP growth rate to estimate the COE, Staff recommends the Commission use the lower end of the range (4.30%) because of the amount of evidence that shows that rational investors would not expect utility per share figures to grow at the same rate as GDP. When using a 4.30% GDP growth rate in Staff's multi-stage DCF results in a COE estimate of approximately 8.54%.

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 October 2012. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending October 31, 2012; that figure was 2.85%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 16). The average beta ("β") for the proxy group was 0.70 and 0.68 if PNM Resources is eliminated which has a beta of 0.95, which is much higher than the next highest beta of .75. 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.[52] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2011, which was 5.70%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2011, which was 4.10%.

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 6.87% and 5.74%, respectively. If PNM Resources is excluded, the results are 6.73% using the long-term arithmetic average risk premium and 5.64% long-term geometric risk premium. While the COE indication using the geometric average risk premium is more than likely below equity discount rates used to value utility stocks, Staff believes the 6.87% COE is quite probable considering the current low bond yield environment. It is generally recognized that the risk premium over Treasury yields is higher than historical averages due to the Fed's efforts to keep Treasury yields quite low. However, this increases the opportunity costs of not investing in utility bonds and stocks, putting upward pressure on the prices of these alternative, low-risk investments.

[52] From Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2012 Yearbook.*

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows an objective test of individual analysts' COE estimates. Because this method is suggested in a textbook[53] used for the curriculum for Chartered Financial Analyst ("CFA") Program, Staff believes this method is free of any bias from those involved in utility ratemaking. It is also a great test because it is very straightforward and limits the risk premium to a 100 basis point range. The COE is estimated by simply 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. Considering that this is based on general U.S. capital market experience and that regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of August, September and October 2012, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 4.63% and 5.22% respectively.[54] Adding a 3% risk premium, the "rule of thumb" indicates a COE between 7.63% and 8.22%. Adding a 4% risk premium, the "rule of thumb" indicates a COE between 8.63% and 9.22%.

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 H), the average authorized ROE for electric utility companies for the first three quarters of 2012 was 10.22% based on 33 decisions (first quarter – 10.84% based on twelve decisions; second quarter – 9.92% based on thirteen decisions; third quarter – 9.78% based on eight decisions). This number is high because the data includes several surcharge/rider generations cases in Virginia that incorporate ROE premiums. Virginia statutes authorize the State Corporations Commission to approve ROE premiums of up to 200 basis points for certain generation projects. Excluding these Virginia surcharge/rider generations cases from the data, the average authorized electric ROE was 9.97% for the

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[53] 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.

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

first three quarters of 2012. The average authorized ROE for electric utility companies for 2011 was 10.22% based on 41 decisions (first quarter – 10.32% based on thirteen decisions; second quarter – 10.12% based on ten decisions; third quarter – 10.00% based on seven decisions; fourth quarter – 10.34% based on eleven decisions).

The average authorized ROR for electric utilities for the first three quarters of 2012 was 7.94% based on 32 decisions (first quarter – 8.00% based on eleven decisions; second quarter – 7.78% based on twelve decisions; third quarter – 8.06 based on nine decisions). The average authorized ROR for electric utilities in 2011 was 7.95% based on 41 decisions (first quarter – 8.12% based on thirteen decisions; second quarter – 8.01% based on ten decisions; third quarter – 8.09% based on seven decisions; fourth quarter – 7.61% based on eleven decisions).

c. Equity Analysts

Past Commission decisions have expressed the view that the COE used by equity analysts is not relevant to determining a reasonable COE estimate in utility ratemaking proceedings. Although Staff respects the Commission's decisions based on the evidence the Commission reviewed in past rate cases, Staff believes it can provide further analysis and explanation that supports the relevance of these COE estimates to the cost of capital determined in a utility rate proceeding.

First, it is important to consider the inherent contradiction caused by using equity analysts' 5-year EPS growth rate forecasts as the constant growth rate of dividends in the single-stage DCF, but ignoring the rest of the analysis performed by the equity analysts. It is naïve to assume that investors would simply take values from the internet without researching the supporting analysis when making investment decisions. While this assumption may allow for expediency in estimating the COE, investors do not make investment decisions with expediency as the priority. Staff has reviewed numerous equity research reports and it has NEVER seen an analyst estimate a fair price for a utility stock by making this naïve assumption. If the equity analysts that provide professional investment advice based on in-depth analysis do not utilize their own growth rates in this manner, then it is completely illogical to make this assumption for purposes of estimating the COE. If the COE is not considered a fair return in terms of the *Hope* and *Bluefield* cases, then the time and effort devoted to rate-of-return testimony would be better spent on determining an appropriate margin over the COE that would be fair in setting the allowed ROE.

Rate-of-return witnesses often cite various academic studies to support their position that investors naively assume that dividends can grow in perpetuity at the same rate as equity analysts' estimates of the 5-year annually compounded EPS growth rate. Although Staff believes the fact that the very equity analysts that provide these forecasts do not make this same assumption when valuing utility stocks disproves this conclusion, it is important to understand the true conclusion of some of these studies. One of the studies often cited to support the use of equity analysts' 5-year EPS growth rate forecasts in the DCF is that of Burton G. Malkiel and John G. Cragg, "Expectations and the Structure of Share Prices." The conclusion of this academic study was that equity analysts' expectations had a greater influence on stock prices compared to simple extrapolations of historical financial data. Staff believes this conclusion is logical considering the vast amounts of resources dedicated to the discipline of securities analysis. However, Staff is not sure how subsequent studies concluded that the results of this study somehow translated into a proof that investors use 5-year EPS forecasts as a constant growth rate in the single-stage DCF methodology. In fact, Cragg and Malkiel did not even use the DCF valuation model when testing their hypothesis regarding the influence of analysts' projections on stock prices. It is more plausible to conclude that, because investors rely on equity analysts' expectations, they rely on their investments recommendations (e.g. buy, sell or hold). Equity analysts' investment recommendations are based on their assessment of the intrinsic value of a given stock. Analysts' methodologies for estimating a fair price varies, but most at least assess the current price-to-forward earnings ratios both on a consensus basis and on the analysts' own estimates. If the analyst believes the company can grow its earnings faster than the consensus and/or the company deserves a higher price-to-earnings ("p/e") ratio than the consensus, then the analyst will expect a higher return than the consensus. In Staff's experience, this is the primary purpose for providing both absolute EPS forecasts and EPS growth rate forecasts. It allows investors to estimate a potential justified p/e multiple.

Cragg and Malkiel specifically indicated the following in their study:

> We would not argue that these estimates necessarily give an accurate picture of general market expectations. It would, however, seem reasonable to suggest that they are representative of opinions of some of the largest professional investment institutions and that they may not be

> wholly unrepresentative of more general expectations. **Since investors consult professional investment institutions in forming their own expectations, individuals' expectations may be strongly influenced – and so reflect – those of their advisers.** That several of our participating firms find it worthwhile to publish these projections and provide them to their customers provides prima facie evidence that a certain segment of the market places some reliance on such information in forming its own expectations. Also, insofar as other security analysts and investors follow the same sorts of procedures as those used by our sample analysts in forming expectations, general investors' expectations would resemble those of analysts. Consequently, these predictions may well serves as acceptable proxies for general expectations and surely seem worthy of detailed analysis. (emphasis added)

In past rate cases the Commission has dismissed evidence Staff presented regarding assumptions investment analysts use to estimate a fair price to pay for utility stocks. Considering the above information, in which the foundation for the study concludes that investors rely and depend on their investment advisors, and therefore, stock prices reflect these expectations, it would seem that the COE assumptions used by these investment analysts are indeed reflected in share prices. To assume that investors utilize the information provided by equity analysts in a way that is wholly inconsistent with how the very analysts that provide them use them, is not supported by any evidence.

Equity analysts often use the dividend discount model ("DDM") to estimate a fair price to pay for the stock. The DDM is synonymous with the DCF in utility ratemaking settings. The DCF in utility ratemaking is simply solving for the required return/cost of equity variable. In valuation, the goal is to solve for the fair price of the stock. Consequently, if equity analysts are of value to their clients, then the stock prices will reflect their estimates of future dividends and the required return on these dividends. Consequently, if one accepts the studies that security analysts' expectations influence investors, which is the conclusion made by Malkiel and Cragg, then this means that stock prices reflect the COE used by these very same analysts. Staff's experience has been that these equity discount rates are usually much lower than COE estimates provided by ROR witnesses in utility rate cases. Staff has provided many examples in the last several rate cases that indicate equity analysts use equity discount rates in the 7% to 9% range when valuing utility stocks. However, this does not mean that these equity analysts expect commissions to allow an ROE equivalent to the market-implied COE. If allowed ROEs were set equal to the COE, this would cause downward pressure on the stock price of a company whose earnings rely primarily on the regulated utility operations. This is the case because utility stock prices currently reflect investors' expectations of regulators continuing to allow returns of close to 10%.

Considering the fact that the Cragg and Malkiel study is the foundation for other studies that are cited to support the use of 5-year EPS forecasts in the constant growth DCF, it is important to understand how at least one of the authors has estimated required returns on stocks in his past studies and how he estimates required returns currently. In his May 1979 study, "The Capital Formation Problem in the United States," Malkiel estimated the required returns on the Dow Jones Industrial Average by using Value Line growth rates for the first five years. This growth rate was then reduced over time to that of the expected real growth rate of the economy, which was 3.6% at the time. [55]

In a recent January 5, 2012 editorial in the *Wall Street Journal*, "Where to Put Your Money in 2012," Burton G. Malkiel provided his opinion on the long-run return expectations for U.S. equities. Malkiel simplified his approach by simply indicating that earnings and dividends in the market have grown at an approximate 5% rate over the long run. He simply added this long-run growth rate to the current approximate 2% dividend yield on the U.S. stock market to arrive at a long-run return estimate of 7% for the U.S. stock market, which is very close to the 6.80% projected return on the S&P 500 estimated by professional forecasters in the First Quarter 2012 *Survey of Professional Forecasters.* If Malkiel believed investors projected returns based on 5-year EPS forecasts on the U.S. stock market, then he would have projected a long-run return of approximately 12.3% (2% dividend yield plus 10.3% 5-year EPS growth forecasts for the S&P 500). He did not. While Malkiel and Cragg's studies certainly concluded that security analysts' estimates have an impact on share prices they did *not* conclude that investors would assume security analysts' 5-year EPS growth rate forecasts are a proxy for perpetual growth.

The focus on earnings growth rates is understandable considering that most security analysts' stock predictions are based on a multiple of p/e ratios, but security analysts provide this information to evaluate potential p/e ratios as they compare to consensus p/e ratios. The ability

[55] The use of a real GDP growth rate for perpetual growth is consistent with Goldman Sachs' valuation approach discussed in the last Ameren Missouri rate case, Case No. ER-2011-0028. While the Commission interpreted this to mean that inflation needed to be added to the real GDP growth rate to make the analysis correct, Malkiel made it clear that he purposely chose real GDP as a perpetual growth rate, but also indicated an argument could be made to use nominal GDP.

of the analyst to accurately project future earnings and justified p/e ratios will determine whether that analyst is successful. Consequently, the focus on analysts' EPS projections is understandable in this context.

H. Cost of Equity Compared to Return on Equity

It would likely be of interest to the Commission that the aforementioned Kihm article is not necessarily advocating that the allowed ROE be set based on a utility company's COE. While it is quite clear that Kihm believes the COE for utilities is in the 7% to 8% range, he does not advocate that commissions set the allowed ROE at this lower level. Kihm is just pointing out that commissions "might be doing the right thing, but for the wrong reason." Kihm is simply trying to emphasize that allowed ROEs should not be assumed to be the COE for purposes of making investment decisions or for purposes of valuing utility assets or securities.

It is also quite clear from Staff's analysis of equity analysts' reports that analysts do not expect commissions to set the authorized ROE equal to the COE. Most equity analysts use a COE in the 7% to 8% range, yet when projecting cash flows generated by the utilities through ratemaking, they assume companies will be authorized an ROE of close to 10%. While the Staff does not believe the Commission should allow investors' expectations of the authorized ROE determine what is authorized in a rate case, Staff does recognize that investors have become accustomed to some margin over the COE being allowed in rates. In fact, some would argue that because book ROEs of the S&P 500 (10% to 15% on average) tend to be higher than the market COE, this may justify the decision to allow an ROE higher than the COE. If the Commission accepts this premise, then the issue before it would be what margin is fair and reasonable for purposes of complying with *Hope* and *Bluefield*. This is a matter that could be explored further if the Commission accepts the notion that the COE is lower than the ROE which it chooses to authorize.

I. 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 7.23% to 7.74% (*see* Schedule 17). This rate was calculated by applying an embedded cost of long-term debt of 5.91% and a cost of common equity range of 8.50% to 9.50% to a capital structure consisting of 51.06% common equity and 48.94% long-term debt. Because there appears to be some concern in setting an allowed ROE based on the COE, Staff recommends the Commission set the allowed ROE at 9.50% in this case. Staff's recommended ROE for Empire is 50 basis points higher than Staff's recent recommendations in the Ameren Missouri, KCPL and GMO rate cases because Staff added 50 basis points due to Empire's lower credit rating, which is based on the business and financial risks of Empire's regulated utility operations. The spreads between 'BBB+'-rated utility bonds and 'BBB-'-rated utility bonds has averaged approximately 45 basis points during the period August 2012 through October 2012.[56] Although this is well-above what Staff believes the true COE to be in the current capital market environment, this allowed ROE would balance the concern about the impact a lower allowed ROE would have on investors' view of Missouri's regulatory environment, while still passing along the benefit of lower capital costs to ratepayers. Also, because Staff's analysis shows a slight decline in the COE since Staff provided its recommendation in the recent Ameren Missouri, KCPL and GMO cases, if the Commission were to set an ROE for Empire relative to the allowed ROEs in these cases, the Commission should take this into consideration.

Staff Expert/Witness: Shana Atkinson

VI. Rate Base

A. Plant in Service

<u>1. Plant in Service as of June 30, 2010</u>

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

Staff Expert/Witness: Amanda C. McMellen

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

2. Iatan 1 Adjustments

The Staff has recommended various disallowances concerning the construction costs incurred on the Iatan Air Quality Control System (AQCS) project. These disallowances were approved on April 12, 2011 by the Commission's Report and Order in KCPL Case No. ER-2010-0355.

Staff Expert/Witness: Amanda C. McMellen

3. Iatan 2 Adjustments

The Staff has recommended various disallowances concerning the construction costs incurred on this project. These disallowances were approved on April 12, 2011 by the Commission's Report and Order in KCPL Case No. ER-2010-0355.

Staff Expert/Witness: Amanda C. McMellen

4. Plum Point Adjustments

The Staff has recommended a disallowance concerning the construction costs incurred on this project. This disallowance is discussed in more detail in the Plum Point construction audit report submitted in Empire Case No. ER-2011-0004.

Staff Expert/Witness: Amanda C. McMellen

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

B. Depreciation Reserve

1. Depreciation Reserve as of June 30, 2010

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

Staff Expert/Witness: Amanda C. McMellen

2. 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

3. 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.

Staff Expert/Witness: Amanda C. McMellen

4. 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"). Staff made adjustments to the plant in service and depreciation reserve in order to eliminate these amounts from cost of service. Since the Staff removed these compensation expenses from its cost of service income statement (*see* Section VIII. E. 2.), Staff is also making an adjustment to remove these costs from rate base in this case.

Staff Expert/Witness: Amanda C. McMellen

C. Cash Working Capital (CWC)

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

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

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

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

Staff's CWC calculation is as follows:

1. Account Description: lists the types of cash expenses which Empire pays on a day-to-day basis.
2. Test Year Expenses: Provides the amount of annualized expense included in Empire's cost of service. These expenses are based on the dollars associated with those items on an adjusted jurisdictional basis according to the account description.
3. Revenue Lag: indicates the number of days between the midpoint of the provision of service by Empire and the payment by the ratepayer for such service. Further explanation of the Revenue Lag can be found later in this Report.
4. Expense Lag: indicates the number of days between the receipt of goods and services by the utility and payment for the goods and services by the utility (i.e. cash expenditures) that are used to provide service to the ratepayer. Further explanation of the Expense Lag can be found later in this Report.
5. Net Lag: results from the subtraction of the Expense Lag from the Revenue Lag.
6. CWC Factor: expresses the CWC Lag in days as a fraction of the total days in the test year. This is accomplished by dividing the Net Lag by 365.
7. CWC Requirement: cash working capital requirement needed for each expense listed. The amounts in this area are calculated by multiplying the test year/annualized balances with the CWC Factor.

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

Staff Expert/Witness: Casey Wolfe

D. Revenue Lag

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

1. Usage Lag: The midpoint of average time elapsed from the beginning of the first day of a service period through the last day of that service period;
2. Billing Lag: The period of time between the last day of the service period and the day the bill for that service period is placed in the mail by the Company; and
3. Collection Lag: The period of time between the day the bill is placed in the mail by the Company and the day the Company receives payment from the ratepayer for the services provided.

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

	Staff
Usage Lag	15.21
Billing Lag	4.30
Collection Lag	27.91
Total Revenue Lag	**47.42**

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

The billing lag is the time it takes between when the Company reads the meter and when the bills are subsequently mailed to customers. Staff used the billing lag calculated in the last Empire rate case, ER-2011-0004, to determine the overall revenue lag in this case.

The collection lag is the time lapse between the point on average when a bill is mailed by Empire and when Empire receives the customer payment. In this case Empire's collection lag is comparable to the number of days in prior cases. Staff accepted Empire's collection lag day calculation in its filed lead/lag study.

The sum of Staff's usage, billing, and collection lags for Empire in this proceeding is 47.42 days.

Staff Expert/Witness: Casey Wolfe

E. Expense Lags

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

Fuel-Coal
Fuel-Gas
Fuel-Oil
Purchased Power
Payroll Expense
Federal Income Tax Withheld
State Income Tax Withheld
Employees 401K Withheld
Employers 401K Matching
Employers Life Insurance Matching
Employers Healthcare
Employers AD&D
Employers Dental/Vision
Vacation

Pension
FICA Withheld
Employer FICA
Federal Unemployment
State Unemployment
Property Taxes
Sales Taxes
Gross Receipts Taxes
Income Tax

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

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

The Cash Vouchers line item in the Staff's CWC Study represents any cash expenses that aren't included in a separate line item on Staff Accounting Schedule 8, Cash Working Capital. For purposes of calculating the cash voucher lag, the Staff used Empire's calculation in the filing of their lead/lag study which included Empire's allocated amount of the payroll taxes billed for the Iatan plant payroll. Empire is billed for its share of operating and maintenance costs for the Iatan generating station by that plant's managing partner, KCPL. Empire requested to create a separate expense lag for its allocated amount of Iatan payroll taxes. Staff does not recommend treating this cost as a separate line item in the CWC schedule, but instead, let it remain in the total cash vouchers lag calculation along with the rest of the billings for the Iatan plant expenses. Empire does not receive a separate invoice for the Iatan payroll taxes; rather Empire receives one invoice for all of its allocation of Iatan costs.

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

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

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

In conclusion, the results of the study performed by Staff resulted in a positive CWC requirement. This means that in the aggregate the shareholders have provided the CWC to the Company during the test year. Therefore, the shareholders should be compensated for the CWC that they provide through an increase to rate base.

Staff Expert/Witness: Casey Wolfe

F. 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 June 2012. There were two accounts added during the test year for Working Funds Iatan (165350) and Working Funds Plum Point (165351) that were excluded in the Staff's average. These are cash accounts, not actual investment in utility assets, and are therefore excluded from rate base.

The Company also holds a variety of materials and supplies (M&S) in inventory so the items can be readily available when needed in performing its utility operations. Staff performed an analysis of all M&S accounts from January 2008 through June 2012. A 13-month average level ending June 30, 2012 was used for the majority of the M&S amounts in the Company's electric account. For these accounts, no upward or downward trend was noted. There were four M&S accounts (154100, 163050, 163801 and 184392) where the most current ending balance was used. These accounts showed a steady trend within the review period and using the last known balance for these four particular accounts is more appropriate than the 13-month average. Account 163999 was normalized based on the most current six months of data due to the irregularities in this account in 2011. There were three accounts (163327, 184220 and 184243) where one month's balance appeared irregular and was replaced with the same month from the previous year. There were three accounts (184242, 184330 and 184416) that were normalized to the current ongoing level. Some of the accounts mentioned above 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 Staff's total level of M&S to arrive at the amount of M&S to be included in electric rate base in this proceeding. Account 184890 was excluded because it is associated with EEI dues that are being disallowed in this case (please refer to Section VIII.G.18., EEI Dues).

Staff Expert/Witness: Amanda C. McMellen

G. 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 units is set by Empire at 60 days. The PRB coal in 2013 will be supplied by two western coal suppliers: Arch Coal Sales and Peabody Coal Sales.

Empire also carries an inventory of local (Kansas) bituminous coal supplied by Foresight Coal Sales, under contract; the days of inventory included for this coal is also 60 days. Staff has also used a 60-day calculation to establish Empire's rate base investment in the coal inventory maintained both at KCPL's 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 multiplied the resulting burn inventory for each unit by the delivered cost of coal per ton for that unit calculated by Staff. To this total Staff then added the fixed cost of basemat coal established in prior Case No. ER-2011-0004 for each unit except 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. The total cost of the burn inventory and basemat 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.

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

Gas Stored Underground - Staff reviewed Empire's General Ledger account for Natural Gas in Storage (Account 151547) and found activity during the test year. Staff reviewed Empire's calculation of the 13-month average inventory cost and concluded the amount was reasonable to include in Staff's rate base.

Staff Expert/Witness: Keith D. Foster

H. Prepaid Pension Asset and FAS 87 and FAS 106 Regulatory Asset Trackers

See the discussion of these items in Section VIII. E. 4. - FAS 87/Pension Expense and Section VIII. E. 5. - FAS 106/OPEBs Expense.

Staff Expert/Witness: Paul R. Harrison

I. 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.

As a result of the Commission's *Order Approving Global Agreement* in Case No. ER-2011-0004 (Empire's last general rate case), Empire's CPC terminated and Empire will utilize a Demand Side Management (DSM) advisory group, which shall not have voting rights.[57]

The DSM Regulatory Asset Account 182318 contains costs that have been incurred for eight (8) DSM programs[58] 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 Empire's DSM advisory group 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 all DSM programs are to be included in rate base as a regulatory asset, as a result of the Commission's *Order Approving Global Agreement* in Case No. ER-2011-0004. The Staff is using the June 30, 2012 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. G. 6. c.).

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

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[57] See Section VIII.G.6.a., Background and Status of DSM.

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

J. Amortization of Electric Plant

Staff has adjusted the amortization reserve for electric plant intangible assets to reflect the updated balances through June 30, 2012. The amortization reserve balance as of June 30, 2012 is $8,653,701 and was included as an offset to rate base in Staff's Accounting Schedules.

Staff Expert/Witness: Amanda C. McMellen

K. Customer Deposits

The amount of customer deposits shown on Accounting Schedule 2, Rate Base, represents a 13-month average (June 2011 - June 2012) 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 $8,497,724 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, 2011 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, $361,153, is included in Staff Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert/Witness: Amanda C. McMellen

L. Customer Advances

Customer advances are funds provided to Empire by individual customers of the Company to assist in recovering 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 June 30, 2012, the end of the Staff's update period in this case, is shown on Accounting Schedule 2, Rate Base.

Staff Expert/Witness: Amanda C. McMellen

M. 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, the amount of depreciation expense used as a deduction for income taxes purposes by Empire is considerably higher than the amount of 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. 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 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.

Staff Expert/Witness: Paul R. Harrison

N. Vegetation Management Tracker Regulatory Asset

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 (i.e., 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 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).

Additionally in the *Global Agreement* and *Nonunanimous Stipulation and Agreement* filed in File No. ER-2011-0004, Appendix B, item 4 stated:

> An annual level of amortization expense for the vegetation management tracker resulting from ER-2010-0130 of $292,514, Missouri jurisdictional. The annual amortization for the balance as a result of ER-2011-0004 is $368,588, Missouri jurisdictional. The regulatory asset included in rate base is in total $3,305,511, Missouri jurisdictional. This is comprised of two components: the net balance of the asset as a result of ER-2010-0130 at $1,299,249, and the balance of the asset as a result of ER-20011-0004 at $2,006,262.

The balance of the vegetation tracker set up in File No. ER-2011-0004 as of March 31, 2011 is $2,479,408. The tracker amount for this File No. ER-2012-0345 is $5,039,187 calculated as the difference between the vegetation management costs and Empire's rate recoveries of vegetation management costs from April 1, 2011 to June 30, 2012. Staff has included these amounts in its rate base. Staff's' cost of service also includes a separate adjustment for the infrastructure remediation and inspection costs incurred by Empire in its cost of service.

Based upon Staff's analysis of the costs associated with the vegetation management tracker in the current case, Staff is recommending that the current tracker continue until Empire's next rate case. The vegetation management costs have continued to rise since Empire's last rate case and have not yet stabilized. If these costs stabilize by the next rate case, a termination of the current tracker will be considered. Based upon its analysis of Empire's ongoing vegetation costs, Staff is recommending that the vegetation management tracker continue and that the asset tracker base amount be changed from 9 million dollars to 12 million dollars. Staff's recommendation does not include any carrying costs in the Empire vegetation management tracker and we will not recommend any carrying costs be included in any future vegetation tracker. Staff has pending data requests concerning the level of increase during the test year and we will continue to evaluate the vegetation costs when we receive the data. Staff will make its final recommendation in its true-up of this case. Staff's adjustments in the Income Statement include a re-basing of Empire's on-going vegetation management costs and to amortize the Commission Rules Tracker balances to expense over a five year period (*see* Section VI. N).

Staff Expert/Witness: Paul R. Harrison

O. Iatan and Plum Point Carrying Costs

1. Iatan 1

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 182308, Iatan Deferred Carrying Costs. (Deferral of carrying costs after a project's in-service date is also known as "construction accounting.") In File No. ER-2010-0130, the Iatan 1 AQCS project was included in Empire's rate base as of December 31, 2009, subject to further review and finalization in the Company's next rate case, File No. ER-2011-0004. Also, in File No. ER-2010-0130, Empire was granted rate recovery of an amortization of Iatan 1 AQCS deferred carrying costs. In the *Report and Order* in KCPL's File No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan accounts. The effect of these disallowances reduces the balance of the Iatan 1 AQCS plant balance. The Staff has removed any construction accounting allowances associated with the portion of Iatan 1 AQCS approved disallowances that were allocated to Empire 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.

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 182332, MO IatanII Df Chg ER-2010-0130. In the *Report and Order* in KCPL's File No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan accounts. The Staff has removed any construction accounting allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire 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 June 30, 2012.

Staff Expert/Witness Amanda C. McMellen

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 182331, MO PlumPt Df Chgs ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for Plum Point (submitted in File No. ER-2011-0004), Staff 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 previous rate proceeding, File No. ER-2010-0103 (September 9, 2010). The construction accounting amounts allowed by the Staff in this proceeding include allowances for depreciation expense, and debt and equity-derived carrying charges. Staff included in its rate base the allowable balance of this deferred asset as of June 30, 2012.

Staff Expert/Witness: Amanda C. McMellen

P. SWPA Hydro Reimbursement

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. In Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to the customers over a ten year period via a tracker mechanism. Staff has included as an offset to rate base the unamortized balance of this tracker.

Staff Expert/Witness: Kimberly K. Bolin

Q. Joplin Tornado O&M Asset

Staff did not include the unamortized balance of the Accounting Authority Order (AAO) granted in Case No. EU-2011-0387 for costs associated with the May 22, 2011, tornado that struck the City of Joplin, Missouri in Empire's rate base. It is an appropriate allocation of the risk associated with extraordinary "acts of God" to share the costs of such events between shareholders and ratepayers by allowing Empire to earn a return of the deferred balance of tornado related costs, but not a return on these dollars.

Staff Expert/Witness: Kimberly K. Bolin

VII. Allocations

A. Corporate Allocations

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

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

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

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

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

Staff Expert/Witness: Jermaine Green

B. Jurisdictional Demand Allocations

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

Demand Allocation Factor

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

Staff is utilizing a Twelve Coincident Peak (12 CP) methodology to determine demand allocation factors for Empire. Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify Empire's peak hourly load in each month for the time period July 2011 through June 2012 and sum the hourly peak loads.

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

c. Divide b. by a. above.

The result is the allocation factor for each jurisdiction:

Retail Operations:

Missouri	.8297
Non - Missouri	.1088
Wholesale Operations:	.0615

Staff Expert/Witness: Alan J. Bax

C. Jurisdictional Energy Allocations

Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor, for each individual jurisdiction, is the ratio of the normalized annual kilowatt-hour (kWh) usage of each particular jurisdiction to the total normalized Empire kWh usage. The kWh usage data includes adjustments for anticipated growth, annualizations and non-normal weather. Staff witnesses Jermaine Green and Seoung Joun Won, respectively, provided the growth and annualization adjustments. Staff witness Shawn E. Lange provided the weather adjustments. Staff has calculated the following energy allocation factors for the particular jurisdictions, utilizing the twelve month period ending June 2012:

Retail Operations:

Missouri	.8179
Non - Missouri	.1111
Wholesale Operations:	.0710

Staff witness Amanda C. McMellen used these demand and energy jurisdictional allocation factors in determining Staff's cost of service for Empire in this case.

Staff Expert/Witness: Alan J. Bax

VIII. Income Statement

A. Rate Revenues

1. Introduction

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

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

Staff Expert/Witness: Jermaine Green

2. Definitions

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

Rate Revenue: Test year rate revenues consist solely of the revenues derived from Empire's charges for providing electric service to its Missouri retail customers (native load). Empire's charges are determined by each customer's usage and the per unit rates that are applied to that usage. Empire's tariff provides that different rates apply to different types of charges (demand vs. energy); and to customers in different rate classes (differentiation by type and amount of use). Fuel Adjustment Clause (FAC) revenues are not included in rate revenues.

Margin from Off-System Sales: Margin from off-system sales is the profits that Empire makes conducting sales of electricity to other utilities at non-regulated prices. The profit margin is calculated as the gross revenues from the sale less the expenses Empire incurs. In the past, such margins have been used to reduce base rates for customers in general rate proceedings. Since Case No. ER-2010-0130, Empire's off-system sale revenues and expenses have been eliminated from consideration in general rate proceedings, and instead are handled entirely through Empire's Fuel Adjustment Clause mechanism.

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

Staff Expert/Witness: Jermaine Green

3. The Development of Rate Revenue in this Case

For purposes of this case, Staff determined 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". Normalization adjustments eliminate the impact from revenues of 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: Jermaine Green

4. Regulatory Adjustments to Update Period Usage and Rate Revenue

a. Update Period Adjustment

To provide a more current basis for normalization, annualization, and growth calculations, Staff determined that usage data used to determine revenue in this case should be updated to reflect the 12 month period ending June 2012.

Staff Experts/Witnesses: Robin Kliethermes and Seoung Joun Won

b. Development of Weather Normalization Factors

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature reaches higher levels, the demand for cooling, air conditioning and fans, increases the customers' consumption of electricity. As the weather becomes cold and temperature falls, the demand for additional heating, electric space heating for example, also forces an increase in electricity consumption. Electric air conditioning and space heating is prevalent in Empire's service territory; therefore, it follows that Empire's electric load is linked and responsive to daily changes in temperature.

December 2011, January 2012, and February 2012 experienced temperatures milder than normal, resulting in electric energy usage below that which would have been expected under normal weather conditions. July 2011, August 2011, and June 2012 experienced temperatures warmer than normal resulting in usage above that which would have been anticipated under normal conditions. The temperatures in the update period used by Staff deviated from normal, thus Staff performed a weather impact analysis.

Staff's model and methodology contained elements important in the class level weather normalization process: use of daily load research data to determine non-linear class specific responses to changes in temperature with the incorporation of different base usage parameters to account for different days of the week, months of the year and holidays. The results of Staff's analysis were provided to Staff witness Dr. Seoung Joun Won to be used in the normalization of revenues for the weather sensitive classes: Residential ("RG"), Commercial ("CB"), Small Heating ("SH"), Total Electric Building ("TEB") and General Power ("GP") classes.

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

Staff Expert/Witness: Shawn E. Lange

c. Weather Normal Variables

Historical Data Used to Calculate Normal Weather Variables - Each year's weather is unique; and, consequently, the usage, the hourly loads, the revenue, and the fuel and purchased power expense need to be adjusted to a level that would be expected under "normal" weather conditions. Staff used actual weather observations for the update period of July 1, 2011, through June 30, 2012, from the Springfield Regional Airport ("SGF") in Springfield, Missouri.

As a measure of "normal" weather, Staff used "climate normals" ("normals") published in July 2011 by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and Atmospheric Administration ("NOAA") as the authoritative definition of normal weather. According to NOAA, a climate normal is defined, by convention, as the arithmetic mean of a climatological element computed over three consecutive decades.[59] To conform to NOAA's three consecutive decade convention for determining normal temperatures, Staff used observed maximum and minimum daily temperatures for the 30-year period of January 1, 1981, through December 31, 2010, the same period in which NOAA bases its calculation of climate normal.

Inconsistencies and biases in the 30-year time series of daily temperature observations occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011. Staff verified the adjustments for anomalies in the SGF time series by direct communication with NCDC, and through Staff's own review of the daily observations. According to NCDC, the serially-complete monthly minimum and maximum temperature data sets have been adjusted to remove all inconsistencies and biases due to changes in the associated historical database. In addition, NCDC confirmed that the observed temperature data needs no adjustment in the period after 2001. Furthermore, Staff's review of NCDC's peer-reviewed, published paper[60] that explains the meteorological and statistical soundness of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies, and found it to be statistically sound.

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[59] Retrieved on July 17, 2012, from NOAA website,
http://www ncdc noaa.gov/oa/climate/normals/usnormals.html.

[60] Menne, M.J., and C.N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, **22**, 1700-1717.

Because Staff uses daily temperature observations to calculate normal weather values and NOAA's normals are monthly values, Staff adjusted the observed daily minimum temperatures so that the monthly average minimum temperature calculated from these adjusted daily values is the same as the NCDC's serially-complete monthly minimum temperature time series. Staff derived the daily mean temperature time series, daily two-day weighted mean temperatures, and normal daily temperatures from these adjusted daily temperatures.

Weather Variables - Because weather fluctuates greatly from day-to-day, the SGF temperature variables required to weather-normalize sales are the update period actual temperatures and the 30-year normal two-day weighted daily mean temperatures. The day's daily mean temperature is generally defined as the simple average of the day's maximum daily temperature and minimum daily temperature. The daily two-day weighted mean temperature is calculated using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight.[61]

This weighted mean is used because yesterday's weather affects how electricity is used today. For example, if yesterday was hot and the air conditioner was on, it is more likely that the air conditioner will be left on today. If yesterday was a mild day and today is slightly hotter, air conditioning may not be used or would be turned on later in the day.

Calculation of "Normal Weather" - Staff used the SGF daily two-day weighted mean temperature data series to normalize both class usage and hourly net system loads. Staff used a ranking method to calculate normal weather 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". Staff ranked the two-day weighted temperatures for each year of the 30-year history from hottest to coldest and then calculated the normal daily temperature values by averaging the ranked two-day weighted mean temperatures for each rank, irrespective of the calendar date. This method results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

[61] To calculate the Dth day's two-day weighted mean temperature (TWMTD), the current day's (D) daily mean temperature (DMTD) is averaged with the prior day's (D-1) daily mean temperature (DMTD-1), applying a 2/3 weight on the current day and 1/3 weight on the prior day: TWMTD = (2/3) DMTD + (1/3) DMTD-1.

Because actual temperatures do not smoothly move up and down from day to day during the year,[62] Staff assigned these normal daily temperatures to the days of the Update Period based on the rankings of the actual temperatures of the Update Period.

This information was used by Staff witness Shawn E. Lange to normalize both the class kWh usage and hourly net system loads.

Staff Expert/Witness: Seoung Joun Won

d. Weather Normalization of Usage and Revenue

Usage and revenue were normalized for the RG, CB, SH, TEB, and 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 update period 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 Shawn E. Lange had provided. This computation resulted in normalized usage by rate block, which were then converted to total normalized revenues by multiplying rate block usage by the appropriate rates.

For the GP and TEB rate schedules, the weather adjustment to rate revenues was calculated by an average realization methodology, excluding customer and demand charges. This methodology assumes that the weather adjustment to usage in each month is distributed into the rate blocks in proportion to the distribution of actual update period 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

e. Annualization for Rate Change

Although the update period begins with the July revenue month, the update period rate revenues do not fully reflect the rate changes implemented on June 15, 2011, as a result of

[62] 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.

Case No. ER-2011-0004, because some bill cycles began prior to June 15, 2011. Thus the update 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 update period. Staff's method of computing annualized revenues for each rate class was to multiply update period billing units by current rates. The difference between these revenues and those billed during the update period under the prior rates provided the amount of the adjustment for the rate change.

Staff Expert/Witness: Non-weather sensitive classes: Robin Kliethermes

Staff Expert/Witness: Weather sensitive classes: Seoung Joun Won

f. 365-Days Adjustment to Revenue

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. The adjustment was made to the update period months in proportion to the actual usage occurring in each month and then applied appropriate rates to determine the revenue adjustment.

For Missouri and Non-Missouri Large Power and Special Transmission Service Contract (Praxair) rate classes, rate revenue and usage is measured by revenue 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 update period and 365 days gives us the days adjustment.

Staff Expert/Witness: Non-weather sensitive classes: Robin Kliethermes

Staff Expert/Witness: Weather sensitive classes: Seoung Joun Won

g. Customer Growth (Annualization)

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 (June 30, 2012) had existed throughout the entire test year. Customer growth was calculated for the RG, CB, SH, TEB, and GP customer classes.

The only retail customer rate class for which this approach is not taken is the LP group. The process used for the LP group is described in subsection h. The Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for RG, CB, SH, TEB, and GP in order to provide the annualized level of sales and revenues at June 30, 2012.

Staff Expert/Witness: Jermaine Green

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

Staff determined annualized, normalized update period usage and revenues for the rate classes determined not to be weather sensitive, i.e., the LP, Praxair, and Non-Missouri LP Customers.

The adjustments are for the update period of July 1, 2011 – June 30, 2012. There were 38 customers in the Missouri LP rate class during the update period and 13 customers in the Non-Missouri LP rate class.

Because each LP 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 Missouri LP customer's individual monthly demand and energy use, measured over multiple years prior to the update period and the 12 months of the update period, were examined graphically to determine whether an adjustment was needed. Out of the 38 Missouri LP customers, three LP customers' loads were adjusted. Additionally, one customer left the LP class permanently. As discussed below, four customers entered the LP rate class.

The thirteen Non-Missouri LP customers were also annualized on an individual customer (account) basis and two customers' loads were adjusted. One of the two customers, whose loads were adjusted, entered Non-Missouri LP from Non-Missouri GP. The load adjustment reflected 12 months of known usage.

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

Staff Expert/Witness: Robin Kliethermes

i. Special Contract Revenue Imputation

The special treatment of the interruptible credits associated with Special Transmission Service Contract: Praxair, Schedule SC-P continues effective through the update period; however, revenues were imputed as if the contract did not exist to prevent harm to other ratepayers.

Staff Expert/Witness: Robin Kliethermes

j. Adjustments for Non-Missouri weather sensitive classes

Staff adjusted the RG, CB, SH, TEB, and GP classes' usage for non-Missouri customers for weather to provide normalized kWh and for the days adjustment. These adjusted usages were provided to the Staff auditors for growth, and to Staff witness Shawn E. Lange for inclusion in Net System Input, and to Staff witness Alan J. Bax for inclusion in jurisdictional allocations.

Staff Expert/Witness: Robin Kliethermes

k. Rate Switching

During the update period, excluding residential customers, sixty-six customers changed rate classes. Nineteen moved between the CB and GP classes, twenty three moved between CB to SH, three moved between CB to TEB, seven moved GP to CB, two moved from GP to TEB, one moved from SH to GP, two moved between SH and TEB, one moved between TEB to GP, four TEB to SH, three moved from GP to LP, and one moved from TEB to LP. 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). The overall effect of rate switching on usage nets to zero (one class' increase exactly equals the other class' decrease), however the overall effect of rate switching is a slight decrease to revenue.

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 update period were then re-priced based on their final rate code and their revenues were added to the final rate code.

Staff Expert/Witness: Non-weather sensitive classes: Robin Kliethermes

Staff Expert/Witness: Weather sensitive classes: Seoung Joun Won

5. Annualization of Excess Facility Charge Revenues

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

Staff Expert/Witness: Robin Kliethermes

6. Other Revenues

a. FAC Revenues

Staff removed from the Fuel Adjustment Clause (FAC) revenues from the Company's test year. This adjustment is made because this revenue will now be collected in base rates rather through the fuel adjustment clause

Staff Expert/Witness: Jermaine Green

b. Unbilled and Gross Receipts Revenues

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

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

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

Staff Expert/Witness: Jermaine Green

c. SO2 Allowances

On January 18, 2005 the Commission approved the *Unanimous Stipulation and Agreement* relating to Empire'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 this case, Case No. ER-2012-0345, the Staff is not proposing an adjustment to SO2 Allowances.

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

Staff Expert/Witness: Jermaine Green

d. Renewable Energy Credits (REC)

In 2005, Empire began receiving wind energy from Elk River Windfarm pursuant to a contract. In addition, Empire began receiving wind energy from Cloud County Wind Farm in 2008, also pursuant to contract. Empire is currently receiving wind energy from both of these entities to meet its customers' energy demand. As a result of these contracts, Empire receives Renewable Energy Credits or Certificates (RECs), which are credits issued under the Center for Resource Solutions' "green-e" program to certify that one megawatt-hour of electricity has been generated by a facility engaged in the production of renewable energy, such as wind, solar or biomass. RECs are tradable and can be bought and sold.

During the test year, Empire booked $2,485,791 of proceeds from sale of RECs into various general ledger accounts. The Staff made an adjustment of $87,208 to the miscellaneous revenue account to increase REC revenue to the level realized during the twelve months ending June 30, 2012, the end of the Staff's update period.

Staff Expert/Witness: Jermaine Green

e. Water Revenues

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

Staff Expert/Witness: Jermaine Green

f. Miscellaneous Revenues

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

Staff Expert/Witness: Jermaine Green

B. Off-System Sales and Transmission

1. SPP Revenues

Empire receives revenues from the Southwest Power Pool (SPP) for its transmission of electricity to other SPP members. Staff reviewed revenues received from SPP since November 2010 for any trends in the data which would indicate that a revenue amount other than the test year revenue would be appropriate to include in the cost of service. Staff's review indicates that the twelve months ending June 30, 2012, the update period, is the most appropriate revenue amount to include in the cost of service as of this filing. Staff is aware of Empire's Transmission Formula Funding tariff that has been filed with the Federal Energy Regulatory Commission (FERC) but is not in effect as of this filing. Approval of this tariff may increase revenues received from SPP but, for this filing, Staff is using historical information for SPP transmission revenues because the effect of the new tariff is not known and measurable at this time.

Staff Expert/Witness: Kimberly K. Bolin

2. SPP Expenses

The SPP is a not-for-profit, regional transmission organization (RTO) which maintains functional control over the transmission assets of its members and provides transmission service through its FERC approved open access transmission tariff (OATT). SPP's costs must be recovered. There are many different fees that the SPP charges, Staff has accepted the test year amounts charged to Empire of all of these costs except for two, Schedule 1a costs (fees to recover administration costs) and Schedule 11 costs (fees to cover the regional transmission costs and construction of transmission projects). Empire has requested that the Company be allowed to set up a SPP transmission tracker that would allow the Company to amortize any over/(under) recovery amounts in the next rate case of the Schedule 1a and Schedule 11 fees paid to the SPP. The Company predicts that the Schedule 1a and Schedule 11 fees will increase significantly in the next few years.

Under its OATT, the SPP establishes a rate for its administration charge (Schedule 1a) annually that allows the SPP to recover 100% of its total annual costs for RTO functions, subject to a rate cap of $.35 per MWh. SPP's administration charge is set each year based on projected costs and revenues. The rate cap serves as a limit on the annual administration charge in order to provide SPP customers a level of certainty and predictability regarding the administrative costs associated with transmission service.

On October 30, 2012 at its Board of Directors/Member Committee meeting, the SPP Board of Directors approved the SPP tariff administrative fee (Schedule 1a) of $.315 per MWh beginning January 1, 2013. The Staff 's annualized amount of SPP Administrative fees in this case are based upon the January 1, 2013 rate of $.315 MWh, since the rate is known and measureable.

Unlike the Schedule 1a fees, Schedule 11 fees vary over time. The rate established for the Schedule 11 fees change as the various transmission customers within the SPP footprint receive approval from FERC to adjust their transmission rates. Staff reviewed Schedule 11 SPP fees charged to Empire since January 2011. Staff compared a 12 month rolling average of Schedule 11 fees and the data indicates that there has been an increase in costs. Staff recommends that the most current data, for the twelve months ending June 30, 2012, be used in setting the Schedule 11 fees charged to Empire.

Staff Expert/Witness: Kimberly K. Bolin

3. Off System Sales

Because Staff excluded the expenses associated with Off-System Sales (OSS), Staff also made an adjustment to eliminate Empire's revenues associated with its Off-System Sales. Therefore the Staff has adjusted Empire's level of test year OSS revenues to zero in Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert/Witness: Jermaine Green

C. 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. In addition to these adjustments, Staff is making an adjustment to eliminate from test year expense the expenses associated with OSS.

Staff Expert/Witness: Keith D. Foster

1. Fixed Costs

Staff does not include fuel and purchased power costs that do not vary directly with fuel burned in its fuel model. These costs are 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 freeze treatment costs for coal deliveries. Staff annualized the natural gas transportation expense based on Empire's current contractual obligations with Southern Star which began on January 1, 2010. In regard to freeze treatment costs, all Powder River Basin (PRB) western coal delivered by rail to Asbury may be subject to being sprayed with a side release for freeze conditioning during the winter months. This treatment just began being applied within the test year. However, Staff could not confirm the treatment was being applied consistently in order to determine an annualized cost. Therefore, Staff used the actual costs for freeze treatment incurred in the test year to add to the total fuel costs.

Staff Expert/Witness: Keith D. Foster

b. Purchased Power – Capacity Charges

In addition to its ownership interest in the Plum Point unit through Plum Point Energy Associates, LLC, Empire has contracted for a reservation 50 MW capacity from Plum Point. For this 50 MW of power, Empire pays for a fixed component and an energy component. The fixed amounts Empire pays are referred to as capacity charges. Generally, there is 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

c. Fuel Prices

Generally, Staff computed its level of fuel expense using prices and quantities contracted by Empire for delivery in 2013, including prices and quantities agreed to in fuel contracts that will become effective as of January 1, 2013 (with one exception described in the "Coal Prices" section below) and for current freight contracts. 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 recommended PRB coal prices reflect Empire's actual contracted coal purchase prices in effect at January 1, 2013 and a 12-month average of transportation costs incurred through the update period, June 30, 2012. Staff's local bituminous coal price reflects Empire's actual contracted coal purchase price in effect at January 1, 2012. For the Plum Point unit, Staff's recommended coal prices reflect the actual contracted coal purchase and transportation prices in effect for 2013. For the Iatan 1 and 2 units, Staff's recommended coal prices reflect KCPL's projected weighted average contracted coal purchase and transportation prices for 2013.

Staff Expert/Witness: Keith D. Foster

ii. Natural Gas Prices

The natural gas price recommended in this case by Staff of $4.92 per MMBtu is composed of two components: hedged and non-hedged (spot) prices. Staff calculated the non-hedged component of natural gas prices 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 June 29, 2012. The weighted average price for the non-hedged component is $3.238 per MMBtu. Staff calculated the hedged component of natural gas costs by applying a weighted average for the actual hedged purchases contracted for at June 30, 2012, that are applicable to Empire's forecasted gas needs for the twelve months ending June 30, 2013. The weighted average price for the hedged component is $5.987 per MMBtu. Staff weighted the hedged gas price at 61% of its overall gas price recommendation, as Empire has contracted to meet approximately 61% of its projected natural gas usage through June 30, 2013, with hedged gas supplies. Empire's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

As noted above, a substantial amount of Empire's natural gas purchases for its electric operations are hedged in advance, with a smaller percentage of such purchases obtained from the spot market. Empire's current policy governing its hedging of natural gas purchases dates back to the early to middle years of the last decade, when natural gas prices were highly volatile. In the last three to four years, natural gas prices have generally become less volatile in nature. Staff recommends that Empire re-examine its hedging policies in light of the current and expected future market for natural gas prices, with the goal of maintaining a reasonable amount of flexibility to allow it to attempt to attain an optimal overall balance between the prices paid for its hedged and spot natural gas purchases.

Staff Expert/Witness: Keith D. Foster

iii. Fuel Oil Prices

Staff used a weighted average price of 2,202.65 cents per MMBtu to determine the fuel oil cost input in the fuel model in this case. Staff calculated this weighted average price 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 $3.070492; and (4) converting this per gallon price into the cents per MMBtu, 2,202.65. Empire burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite storage at its various facilities in sufficient capacity that only occasional purchases are necessary. As a result, Empire does not contract for or hedge oil costs.

Staff Expert/Witness: Keith D. Foster

2. Losses (Including FAC Filing Requirements)

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 2012, as 6.62% of NSI. Staff witness Shawn E. Lange used this loss percentage in the development of hourly loads used in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

3. Fuel and Purchase Power Expense

a. Variable Fuel Expense

The Staff estimates the variable fuel and purchased power expense for Empire for the modified year, as defined in the Rate Revenue Section of Staff's Cost of Service Report, ending June 29, 2012 to be $141,231,864 without off-system sales.

To develop this estimate, Staff uses the RealTime® production cost model to perform an hour-by-hour chronological simulation of Empire's generation and power purchases. Staff uses the model to determine the annual variable cost of fuel and the net purchased power energy costs and fuel consumption necessary to economically meet Empire's hourly load requirements during the test year (as updated), within the operating constraints of Empire's resources. These results were supplied to Staff witness Keith D. Foster for use in annualizing fuel expense.

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

Model inputs calculated by Staff are: fuel prices, spot market purchased power prices and availability, hourly NSI, and unit planned and forced outages. Staff relied on Empire filed testimony, work papers and responses to data requests for factors relating to each generating unit. These factors include: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Firm purchased power contract information, such as hourly energy available and price, are also inputs to the model.

Staff Expert/Witness: David W. Elliott

i. Capacity Contract Prices and Energy

Capacity contracts are contracts entered into between electric providers for a specific amount of capacity (megawatts) and a maximum amount of hourly energy (megawatthours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. Empire's capacity contracts include the Elk River and Meridian Way Wind Contracts, and the Plum Point Contract.

Empire's actual hourly contract transaction prices were obtained from the data Empire supplied to comply with 4 CSR 240-3.190 and were used by the Staff to calculate each contract's average monthly prices.

Staff Expert/Witness: David W. Elliott

ii. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the Empire generating unit outages were normalized by averaging the six and a half years of actual values taken from data supplied by Empire to comply with 4 CSR 240-3.190.

Staff Expert/Witness: David W. Elliott

iii. Normalized Net System Input

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

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

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

This process includes many checks and balances, which are included in the spreadsheets that are used by Staff. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[63]

After weather-normalizing and annualizing usage for Empire's Missouri jurisdictional retail customer classes is completed, weather-normalized wholesale usage as well as any non-Missouri jurisdictional usage is added to produce an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with Staff's Missouri jurisdictional normalized revenues.

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

Staff Expert/Witness: Shawn E. Lange

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

iv. Hourly Purchase Power Prices

Spot market purchases are purchases of energy made 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 economics and availability of its generating units and capacity purchases. Purchases of spot energy are made in order to lower costs when the spot market prices is below both the marginal cost of providing that energy from the Company's generating units and the utility's firm capacity purchases. Since the spot market depends on energy supply and demand in each hour, the prices tend to be much more volatile than firm capacity purchases. The Staff used a procedure developed by the Commission's Energy Department-Engineering Section in 1996 that is described in the document entitled "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market" (March 18, 1996) attached in Appendix 3 as Schedule ELM-1. The method uses a statistical calculation based on the truncated normal distribution curve by hour by month 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 29, 2012. 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 Expert/Witness: Erin L. Maloney

4. 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 at the current contract rate effective June 1, 2012.

Staff Expert/Witness: Keith D. Foster

D. Depreciation

Staff recommends the Commission:

- The Commission order the depreciation rates for the production accounts requested by Staff in Recognition of the Commission's Orders applying the methods and assumptions used in the recent KCPL, GMO, and Ameren Missouri cases ER-2010-0355, ER-2010-00356, and ER-2010-0036, respectively as shown in Appendix 3, Schedule JAR(DEP)-1.

- The Commission order Empire to continue the use of the depreciation rates for the transmission, distribution, and general plant accounts ordered in Case No. ER-2011-0004. The method for determining depreciation rates remains unchanged, as shown in Appendix 3, Schedule JAR(DEP)-1.

- Make no adjustment at this time to provide accelerated depreciation related to the potential retirement of Asbury 2, Riverton 7, Riverton 8, and Riverton 9.

- Order a total Company addition to the depreciation reserve in the amount of $5,471,674 to account 312 regarding a prior retirement of a steel unit train at the Asbury generation facility.

1. Purpose of Depreciation

The National Association of Railroad and Utilities Commissioners in 1958 approved this definition of 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.[64]

The purpose of depreciation in a regulatory setting is to provide for shareholder recovery of their investment in capital assets over the length of time that the assets are in service. 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.

[64] Public Utility Depreciation Practices, August 1996, Published by the National Association of Regulatory Utility Commissioners

Recovery of the annual depreciation expense returns to the Company's shareholders a portion of the investment in the capital assets each period. In Missouri's regulatory setting, this return is commonly referred to as a return of capital. Depreciation expense is accrued in an accumulated depreciation reserve for the eventual retirement of plant in service. FERC – Uniform System of Accounts (USOA) states that this reserve accrual rate is to be accumulated with guidance provided by account 108 *Accumulated provision for depreciation of electric utility plant*. Any as of yet unrecovered or undepreciated amounts for the costs of the capital assets held in service by the Company, are known as net plant-in-service, and will be returned to the Company's shareholders in future depreciation accrual periods. The Company is permitted to earn a return on these undepreciated capital assets in rate base, commonly referred to as a return on net plant-in-service, a component of rate base. In a regulatory setting this return is commonly referred to as a return on capital.

2. Analysis of Accumulated Reserve for Depreciation

Another analysis performed as part of a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. The purpose of this analysis is to determine whether prior depreciation estimates have differed significantly from actual experience, and to determine whether corrective action should be considered. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date.

The depreciation reserve for a particular account is the amount for plant investment and estimated net cost of removal that have been recovered in depreciation rates over the life of the capital assets within the account. The capital assets in service are reduced by retirements, costs of removal, and transfers out. Capital assets in service are 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 identification of any reserve over- or under-recovery during examination of the adequacy of the accumulated reserve for depreciation does not in itself warrant corrective action. 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. Those factors would typically include 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. The depreciation estimation process is dynamic and it is possible that the currently determined average service life (ASL) recommended by Staff will differ from the ASL that Empire will actually experience. Since future service life estimates for particular plant sites are necessarily only estimates, it is possible that some plant sites' life estimates may be long, and others short, but that the aggregated accrued reserve and aggregated theoretical reserve are reasonable in balance.

Based upon the Commission's currently ordered depreciation rates for Empire, the reserve for depreciation is over-accrued by $72,132,008 at the filing of direct testimony in Case No. ER-2011-0004. This amount has continued to increase since Empire's depreciation rates were last ordered in Case No. ER-2011-0004. Although the reserve is over-accrued, when the actual reserve is compared to the theoretical reserve that is calculated based on current rates, the actual reserve is not significantly over-accrued when calculated based on the depreciation rates Staff is recommending in this case. Thus, Staff is not recommending a corrective action to adjust the depreciation reserve by decreasing the depreciation rates in this case.

Staff's recommended depreciation rates for the Production Plant accounts are, in general, higher than the currently-ordered depreciation rates for those accounts. When the theoretical reserve is analyzed with these new rates the result is to significantly reduce the difference between actual book reserve and the theoretical reserve.

3. Asset Management

The FERC provides specific instructions and guidance through its direction of regulated electric company compliance with the USOA. The USOA defines these instructions and guidance, most specifically through a set of definitions. These definitions are in turn used to establish accounting rules and ultimately a chart or system of accounts wherein a utility will record and track the disposition of its assets. The USOA states that there are four classes of assets and these are common to all utilities. The first class contains the production accounts.

These production accounts are numbered Account 310, Land and Land Rights, through Account 349, for which no designation currently exists. The second group of assets provided for in the USOA is transmission. These transmission accounts are numbered Account 350, Land and Land Rights, through Account 359.1, Asset Retirement Costs for Distribution Plant. The third group of assets provided for in the USOA is distribution. These distribution accounts are numbered Account 360, Land and Land Rights, through Account 374, Asset Retirement Costs for Distribution Plant. The fourth class of assets provided for in the USOA is the general plant accounts. These general accounts are numbered Account 389, Land and Land Rights, through Account 399.1, Asset Retirement Costs for General Plant.

By categorizing the above assets into classes, accounts and sub-accounts, a utility is able to better track assets by function. For depreciation purposes, the depreciation engineer looks at these asset types by engineered purpose and use. Furthermore, the depreciation engineer will perform a mathematical analysis of the dollars invested in each account to determine what the average service life is by account that is composed of retirement units. If dates of dollars by retirement unit being placed in service are not recorded or dates of dollars by retirement unit being taken out of service are not recorded, there is not sufficient information to do a reliable analysis of the dollars representing retirement units placed in and out of service (additions and retirements by account) to determine service life. By analogy, if a car did not come with a model year and an odometer it would be a lot harder to determine an estimate of its useful life.

<u>4. Depreciation Rates</u>

The Commission accepted the use of parameters involving the life span method and remaining life technique for developing depreciation rates, in the recent KCPL, GMO, and Ameren Missouri cases, Case Nos. ER-2010-0355, ER-2010-0356, and ER-2010-0036, respectively. In recognition of these decisions, Staff performed a depreciation study using these parameters for Empire's production accounts. Staff performed this depreciation study using the same depreciation data set as used in the Company's previous rate case, which results in the depreciation rates for production plant accounts set out in Appendix 3, Schedule JAR(DEP)-1. Staff has reviewed and considered utilization of this method in this and past cases. Staff will continue to monitor and reassess in each submitted depreciation study the adequacy and efficacy of this and alternative methods used to derive depreciation accrual rates.

5. Depreciation Reserve

As stated in the FERC description of balance sheet accounts, account 108, *Accumulated provision for depreciation of electric utility plant*, for general ledger and balance sheet purposes, shall be regarded and treated as a single composite provision for depreciation. The FERC further describes that for purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the following functional classification for electric plant: (1) Steam production, (2) Nuclear production, (3) Hydraulic production, (4) Other production, (5) Transmission, (6) Distribution, (7) Regional Transmission and Market Operation, and (8) General. These subsidiary records shall reflect the current credits and debits to this account in sufficient detail to show separately for each such functional classification (a) the amount of accrual for depreciation, (b) the book cost of property retired, (c) cost of removal, (d) salvage, and (e) other items, including recoveries from insurance.

The utility is restricted in its use of the accumulated provision for depreciation to the purposes set forth in account 108. It cannot transfer any portion of these accounts to retained earnings or make any other use thereof without authorization by the Commission.

However, the Company may not maintain all or a portion of these dollar amounts to be withdrawn in the future but clearly maintains the liability for these depreciation reserve amounts. After all, the depreciation or amortization accretion is a return of the investment made by shareholders on ratepayers' behalf.

As noted earlier account 108 is the account from which depreciation reserves will be withdrawn for retirements as accounted for by functional classification. In this example production plant depreciation rates were initially developed for a composite of all assets under an account number as previously described under the Asset Management section of this testimony. Due to the fact that depreciation rates are periodically changed as a result of required periodic depreciation or the fact that the Company has changed the method by which it computes the annual depreciation accrual, there is no record of what amounts of depreciation reserve were actually accrued for any specific asset or unit. Consequently any over or under accrual of reserve for any asset less than functional classification is beyond the precision involved in regulatory depreciation historically practiced.

6. Asbury Unit Train Concerns

Staff has investigated Empire's retirement of a unit train at the Asbury generating facility. Staff has three main concerns about the unit train:

- The steel unit train was leased out by Empire to a non-utility party for a ** ________ ** period of time while the Company continued to collect depreciation expense, yet Empire did not record the lease revenues/expenses to its regulated books.
- Once the train was fully accrued in March of 2007, Empire stopped accumulating depreciation for the eight (8) months following until such time when the train was sold, although it continued to recover depreciation expense from ratepayers.

Empire failed to record the sale proceeds and sale expenses of the steel unit train on Empire's regulated books.

The Company leased the steel unit train at Asbury to a non-utility party. The length of that lease contract according to the data request was ** ________ **; the Company would be receiving ** ________________ ** over the length of the contract. The total amount collected over the entire length of the lease was ** ________ **. The income collected from the lease of the train should have been accounted for on Empire's books as money placed into the depreciation reserve account 312 where the unit train had been booked. Staff recommends an adjustment in the form of a total Company addition of ** ________ ** to the reserves for Account 312. This adjustment is necessary to properly record the revenues Empire received from the use of this train while Empire was receiving depreciation expense for the train from ratepayers, and for which Empire was receiving rate base treatment.

The second issue related to the steel unit train at the Asbury generating facility is that the Company stopped recording accrual of depreciation expense on the unit train from April 2007 through November 2007 when the unit train was sold. The Company continued to collect depreciation during the entire time of the lease when the Company was receiving income from a non-utility party. The Company fully collected the original cost of the unit train in March of 2007. In April of 2007 the Company stopped accumulating depreciation on the unit train, which would mean the Company was then collecting those dollars built into rates associated with the unit train depreciation expense as profit rather than booking an accrual to accumulated depreciation reserves, as the Commission previously ordered in Case No. ER-2005-0470. Staff recommends an adjustment to the depreciation reserves for account 312 with a total Company addition of $248,137 for stopped depreciation accrual related to the eight (8) months prior to the sale of the unit train.

The final issue is related to the sale of the unit train and the recording of salvage related to the income from the sale. According to the Company's annual FERC Form 1 from 2007 and 2008, the sale of the steel unit train at Asbury was recognized as a pure profit sale minus the cost of the sale contract. This fact is further corroborated with the response to Data Request No. 0240 in Case No. ER-2011-0004. The income from the sale of the unit train for $1,250,000 minus sale contract cost should have been booked to the depreciation reserves as salvage for the unit train. Staff recommends an adjustment to the depreciation reserves for a total Company additional amount of $1,241,287. In total, Staff recommends a **__________ ** total Company addition to the depreciation reserve for account 312 to reflect stopped depreciation, sale proceeds (salvage), and lease income/expense from the Asbury unit train from **____ ** through **____ **.

7. Recommendations

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

1. The Commission order the depreciation rates for the production accounts requested by Staff in Recognition of the Commission's Orders accepting the methods and assumptions used in the recent KCPL, -GMO, and Ameren Missouri cases ER-2010-0355, ER-2010-00356, and ER-2010-0036, respectively as shown in Appendix 3, Schedule JAR(DEP)-1.

2. The Commission order Empire to continue the use of the depreciation rates for the transmission, distribution, and general plant accounts ordered in Case No. ER-2011-0004, method for determining depreciation rates unchanged, respectively as shown in Appendix 3, Schedule JAR(DEP)-1.

3. Staff does not recommend any reserve amortizations as a result of its revised depreciation methodology.

4. A ** ________ ** total Company addition to the depreciation reserve for account 312 to reflect stopped depreciation, sale proceeds (salvage), and lease income/expense from the Asbury unit train from ** ____ ** through ** ____ **.

Staff Expert/Witness: John A. Robinett

E. Payroll and Benefits

1. Payroll, Payroll Taxes and 401(k)

Staff adjusted Empire's test year payroll expense to reflect an annualized level of payroll, payroll taxes, and 401(k) benefit costs as of June 30, 2012. Base payroll was calculated by multiplying employee levels at June 30, 2012, by the then-current appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll for Empire was calculated for each full-time hourly employee based upon an overtime percentage computed for non-union and union employees. The overtime percentage for each was calculated by (1) annualizing the five-year average of overtime hours actually incurred, (2) multiplying that by the current average rate paid for overtime as of June 2012, and (3) dividing the product by Staff's pro forma base payroll amount. Staff removed from its calculation of this average the overtime hours associated with the January and December 2007 ice storms, and the May 2011 Joplin tornado.

In regards to the Joplin tornado, Empire was granted an Accounting Authority Order (AAO) to defer all incremental Operations & Maintenance (O&M) costs associated with the tornado. Any overtime costs incurred as a result of this tornado needed to be removed in order to avoid a situation where Empire could potentially recover those costs twice in rates.

An allocation rate for distributing the payroll adjustment was determined by using 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 March 31, 2012. 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 required to restate the test year payroll to an annualized level as of June 30, 2012.

NP

Staff calculated payroll taxes based upon June 30, 2012 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 June 30, 2012.

Staff Expert/Witness: Casey Wolfe

2. Incentive Compensation

Staff has reviewed Empire's portfolio of incentive compensation plans offered to its employees. Based upon this review, Staff is proposing adjustments to 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 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. In 2011, 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 would have been 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 would not have received 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 would have received double the target MIP award for that specific goal.

Prior to 2012, the payout of pre-set MIP goals was dependent upon Empire maintaining its common stock dividend. If a dividend was not paid out for a given year, or if the dividend was reduced in a given year, no MIP was to be awarded. In May 2011, Empire announced that it was suspending payment of its dividend for the remainder of calendar year 2011. Therefore, no MIP awards were paid to Empire's officers in early 2012 for goals attained for calendar year 2011. Instead, a "discretionary" incentive award was given to the senior officers early in 2012 in accordance with their base salary.

Staff's policy is to not include incentive amounts in rates that have no set performance measures to attain, such as is the case with the 2011 discretionary award. However, Staff realizes that the events that took place in 2011 constituted an "abnormal" year for Empire's incentive compensation expense, and that in past cases some amount of MIP expense was included in Empire's rates. In order to determine the appropriate amount to include for the MIP in this case, Staff developed an average of prior case MIP amounts it recommended be included in Empire's rates going back to Empire's 2004 electric rate case, and also included in the average the zero MIP amount applicable to 2011, and included this amount in the payroll adjustment.

b. Lightning Bolts

Empire's "Lightning Bolts" program offers one-time incentive payments in the nature of bonuses to certain employees. Staff has disallowed the cost of these discretionary bonuses paid in the test year. The Commission's *Report and Order* in Case No. ER-2006-0315 adopted 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, 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. 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 Wolfe

3. Payroll Benefits

Empire currently offers its employees Dental, Vision, Healthcare and Life Insurance benefits. Staff performed an analysis of the employee benefit costs included in Account 926 from the general ledger. Staff annualized each expense by examining the individual costs over a four (4) year period to determine the appropriate amount to include for each expense. Health and Dental Insurance costs increased from year to year. Because there was an obvious increase in costs, Staff included these expenses at the most current annual amount through the end of the update period, June 30, 2012. Vision Insurance has been consistent in total costs for the last three (3) years. Since the total costs of Vision Insurance have not materially varied over this time period, Staff used the most current costs as of the twelve months ending June 30, 2012 to annualize Vision Insurance to include in the cost of service. Life Insurance costs have been somewhat sporadic over the last four (4) years. To annualize Life Insurance, Staff used a four (4) year average of total costs to include in the cost of service.

Staff Expert/Witness: Casey Wolfe

4. 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 and the *Stipulation and Agreement as to Certain Issues*, entered into in Case No. ER-2010-0130. 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-2011-0004. These above-referenced agreements provide for Empire to generally 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 five 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.

Additionally, Staff has included a prepaid pension asset (PPA) in rate base in the amount of $19,564,559. The PPA represents the cumulative amount of contributions in excess of actuarial costs as of June 30, 2012. These contributions were made to prevent the pension plan from becoming "at-risk" as defined under the Pension Protection Act, and to meet the obligations of the Pension Benefit Guarantee Corporation. Staff's cost of service does not include an amortization of this PPA. Future contributions will be reduced by this PPA amount.

Empire's pension costs in this case were based upon Exhibit 1 of Empire's 2012 Pension Expense and workpapers. Staff did not receive Empire's actuary report until the day before Staff filed this testimony. Staff will update the pension costs, tracker balance and amortization in its True-Up testimony. The results of the Staff's review of Empire's pension costs are as follows:

1. The Company's ongoing FAS 87 expense recognized in rates in this case is $7,678,726.

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 June 30, 2012, was $3,337,728, which is to be amortized over five years as an expense in the amount of $667,546

3. The amount to be included in rate base for Empire's ongoing pension expense tracker mechanism is $3,337,728, as noted above.

4. An amount of $19,564,559 is included in Empire's rate base as a prepaid pension asset.

Staff Expert/Witness: Paul R. Harrison

5. FAS 106 – Other Post Retirement Benefit Costs (OPEBs)

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. The 2006 agreement was later modified by the *Stipulation and Agreement as to Certain Issues* reached in Case No. ER-2008-0093, and the *Stipulation and Agreement as to Certain Issues* reached in Case No. ER-2010-0130. 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-2011-0004. 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 a 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 four electric rate cases for ratemaking treatment of OPEBs costs. Empire's OPEB costs in this case were based upon Exhibit 3 of Empire's 2012 OPEB expense and workpapers. Staff did not receive Empire's actuary report until the day before Staff filed this testimony. Staff will update the OPEB costs, tracker balance and amortization in it True-Up testimony. The results of the Staff's review of Empire's OPEB costs are as follows:

1. The Company's ongoing FAS 106 cost recognized in rates in this case is $1,732,080.

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 June 30, 2012, was ($1,287,060), which is to be amortized over five years as a reduction to expense in the amount of ($257,412).

3. Rate base is reduced by the level of regulatory liability associated with Empire's ongoing OPEBs tracker mechanism, $1,287,060 as noted above.

Staff Expert/Witness: Paul R. Harrison

6. Supplemental Executive Retirement Plan (SERP)

Certain management employees receive benefits under Empire's Supplemental Employee Retirement Program (SERP). The provisions of FAS 87 are used to calculate the annual financial reporting expense accrual for this plan. Due to the fact that the benefits from this retirement program are not available to a broad range of employees, this program is designated as a "non-qualified" plan. In a non-qualified plan, only the amounts paid to beneficiaries are tax deductible. Staff used a five-year average of actual payments made in calculating the annual cost of the SERP for inclusion in rates.

Staff Expert/Witness: Paul R. Harrison

F. Maintenance Normalization Adjustments

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

1. Iatan

Staff noted the Iatan 1 production station is on a six-year major maintenance cycle. For that reason, Staff used a six-year average of maintenance costs. Empire owns only 12% of the Iatan 1 unit.

2. Asbury

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

3. Riverton

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

4. State Line Combined Cycle (SLCC) and State Line Common

The SLCC maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. Empire owns 60% of the SLCC unit, with Westar Energy owning the remaining 40%. Staff subtracted 40% of SLCC expenses incurred in the test year ended March 31, 2012, to adjust out Westar's portion of test year expenses. Staff then applied an adjustment based on a five-year average of Empire's portion of maintenance costs.

Empire is responsible for 66.67% of the State Line Common maintenance expenses, while Westar Energy is responsible for the remaining 33.33%. Staff subtracted 33.33% of State Line Common expenses incurred in the test year ended March 31, 2012 to adjust out Westar's portion of test year expenses. Staff then applied an adjustment based on a five-year average of Empire's portion of maintenance costs.

5. State Line 1 and Energy Center 1 and 2

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

6. Operations and Maintenance (O&M) Expenses for Iatan 2, Iatan Common, and Plum Point

In Case No. ER-2011-0004, Staff recommended a tracker for Iatan 2 and Plum Point O&M expense, because there was not adequate information to develop a reasonable annualized and normalized expense level. Since Iatan 2 met its in-service criteria on August 26, 2010, and Plum Point met its in-service criteria on August 13, 2010, and given Empire's limited operating experience with Iatan 2 and Plum Point at the time of Case No. ER-2011-0004, an O&M tracker was suggested to protect 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. Empire and other signatory parties agreed through a *Global Agreement* in Case No. ER-2011-0004 to establish a tracker for Iatan 2, Iatan Common, and Plum Point O&M costs and on June 1, 2011, the Commission approved the use of a tracker for these costs. The effective date of the tracker mechanism was established by the Commission at June 15, 2011.

In this case, Staff analyzed the Iatan 2, Iatan Common, and Plum Point O&M costs beginning June 15, 2011, through June 30, 2012, the update period for this case. For this same time period, Staff then calculated the total O&M costs, including only the accounts identified in the computation of the base tracker amounts established in Case No. ER-2011-0004. Base tracker amounts were only identified for Iatan 2 and Plum Point, so there was not a base amount for Iatan Common. Staff then compared the total O&M costs from June 15, 2011, through June 30, 2012, to the base tracker amounts (zero for Iatan Common) to determine the associated regulatory asset or liability for each plant. Since a base tracker amount for Iatan Common was not established in Case No ER-2011-0004, Staff recommends an ongoing annualized level of Iatan Common O&M expenses of $2,424,701 Missouri jurisdictional. This represents the O&M expenses incurred by Empire for the year ending June 30, 2012, and would be the base tracker amount going forward. In addition to determining an ongoing level of Iatan Common O&M expenses, Staff recommends recovery of the excess costs over the base amount established in the *Global Agreement* in Case No. ER-2011-0004. Staff recommends a three (3)-year amortization of the excess costs over the base amount.

As previously mentioned, Iatan 2 was placed in service on August 26, 2010, and Plum Point was placed in service on August 13, 2010. At the end of the true-up period for this case, December 31, 2012, each plant will have operated for approximately two (2) years and four (4) months. Since both plants are still in the early stages of operation, two (2) years and four (4) months is not an adequate period of time to recommend an annualized level of O&M expense for two new coal fired power plants. Therefore, Staff recommends the continuation of the Iatan 2 and Plum Point trackers at the base amounts established in Case No. ER-2011-0004, and the Iatan Common tracker at the annualized level discussed above.

Staff Expert/Witness: Keith D. Foster

G. Other Non-Labor Expenses

1. Customer Deposit Interest Expense

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

Staff Expert/Witness: Amanda C. McMellen

2. 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.

Staff determined its adjustment for property taxes by developing a property tax rate to be applied to total electric plant in service as of December 31, 2011. To develop the property tax rate, the Staff divided the amount of total property taxes due in calendar years 2007 - 2011 by the total plant in service for each year on January 1, 2007 to January 1, 2011. This property tax rate was then applied to total electric plant in service on December 31, 2011, to arrive at annualized property taxes. The annualized property tax expense was then subtracted from test year property tax expense to derive the adjustment.

One minor difference in the current rate case for property taxes is the treatment of the Plum Point Generating Unit located in Arkansas. The owners of the Plum Point unit, including Empire, have entered into an agreement with the City of Osceola, Arkansas; Mississippi County, Arkansas; Osceola School District No. 1 of Mississippi County, Arkansas; and Mississippi County Community College District of Arkansas to make an annual Payment in Lieu of Taxes (PILOT) instead of paying property taxes on the unit in the normal manner. A PILOT agreement allows the owners of the Plum Point unit to pay one flat rate of property taxes on the Plum Point unit for 30 years with the potential for an extension at the end of the 30 year term, regardless of any additions or retirements made to the unit since its in-service date. To appropriately calculate the overall property tax amount for Empire, the amount of Empire's share of the Plum Point plant had to be subtracted from total plant in service so as not to be included in the development of the annualized property taxes. The set amount of PILOT taxes that Empire has agreed to pay for Plum Point was then added to the annualized property tax calculation to determine the total property tax adjustment.

Property tax expense arrived at in this manner is the best estimate available of ongoing levels of these taxes, and is consistent with how property taxes have been calculated for rate purposes in the past for Empire and other Missouri utilities.

Staff Expert/Witness: Casey Wolfe

3. Franchise Taxes

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

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

Staff Expert/Witness: Amanda C. McMellen

4. Amortization Expenses

a. Amortization of Electric Plant

Staff analyzed all amortization expense booked to Account 404.000, Amortization-Limited Term Electric Plant. Staff's adjustment increased expense to reflect the annualized amortization based on updated information through June 30, 2012, (as described earlier in Section VI. J). Amortizations that expired during the test year or will expire through the true-up period in this case (December 31, 2012) were eliminated from the annualization.

Staff Expert/Witness: Amanda C. McMellen

b. Amortization of Stock Issuance Costs

In 2008, 2009, 2010, and 2011 Empire made additional issuances of common equity. In making all of these issuances, the Company incurred costs totaling $4,145,837 (including incremental costs incurred by Empire to its equity distribution program since its inception) for its electric operations. It is Staff's position that these costs be recovered through rates as an above-the-line adjustment to operating expenses. 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 expansive for Empire employees to handle on their own, the Company hired various contractors and received assistance from other utilities to aid in the restoration efforts. Empire tracked all incremental expenses associated with the ice storms separately. Some storm costs were capitalized and have been included in Empire's plant in service balances. For the costs that were not capitalized, the Company requested in Case No. ER-2008-0093 that these expenses be amortized over five-years. Empire began booking the January 2007 ice storm amortization in February 2007, and the December 2007 ice storm amortization in January 2008. Costs associated with the January 2007 ice storm were fully amortized as of the end of January 2012. The December 2007 ice storm costs will be fully amortized as of December 2012.

Therefore, both ice storm expense amortizations have been eliminated from cost of service in this case.

Staff Expert/Witness: Amanda C. McMellen

5. Iatan Carrying Costs Amortization

The Company has deferred its carrying costs (monthly depreciation and monthly debt and equity-derived carrying charges) for its Iatan 1 AQCS Account 182.308 - Iatan Deferred Carrying Costs, Iatan 2 Account 182.332 - MO IatanII Df Chg ER-2010-0130 and Plum Point Account 182331 - MO PlumPt Df Chgs ER-2010-0130. This deferral of carrying costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments were authorized under Empire's Regulatory Plan, approved by the Commission in Case No. EO-2005-0263. Staff recommends amortization of these carrying costs using a composite amortization rate derived from dividing the total depreciation expense for each plant by the total plant balance for each plant. Staff used these composite rates and calculated amortization amounts of $84,729, $44,828, and $1,987 for Iatan 1 AQCS, Iatan 2, and Plum Point, respectively, for inclusion in this rate case. The amortization amounts are based upon the Company's deferred asset balances for these items of $4,670,565, $2,534,784, and $118,061 for Iatan 1 AQCS, Iatan 2, and Plum Point, respectively, as of June 30, 2012.

Staff Expert/Witness: Amanda C. McMellen

6. Demand Side Management

a. Background and Status of DSM

Staff recommends that the Commission order the continuation of the current Empire DSM regulatory asset account mechanism[65] in this case to allow full recovery of direct program costs for the Company's five (5) energy efficiency programs, one (1) demand response program, and two (2) affordability program.[66]

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[65] See the section of this Staff Report titled Empire's DSM Cost Recovery Mechanism for a description of Empire's DSM regulatory asset account mechanism.

[66] Direct testimony of Aaron J. Doll at page 11, lines 5 through 9: The five Residential programs are: Low-Income New Home, High Efficiency Residential Central Air Conditioning Rebate, Energy Star® New Homes, Home Performance with Energy Star, and Weatherization. The two Commercial & Industrial programs are the

Empire began implementing 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, which approved Empire's Experimental Regulatory Plan. The Experimental Regulatory Plan established the Customer Programs Collaborative ("CPC") to make decisions (through a prescribed voting process) pertaining to Empire's affordability, energy efficiency and demand response programs ("Customer Programs"). Members of the CPC include Empire, Staff, Office of the Public Counsel ("OPC"), Missouri Department of Natural Resources and industrial intervenors Praxair, Inc. and Explorer Pipeline Company. Each CPC member had 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[67].

Empire's Experimental Regulatory Plan expired on June 15, 2011,[68] as a result of the Commission's June 1, 2011 *Order Approving Global Agreement* in Case No. ER-2011-0004 (Empire's last general rate case) which ordered the following related to the Company's DSM programs:

- Paragraph 8: Consistent with its commitments in File No. EO-2011-0066, Empire will fulfill its obligations concerning DSM programs to be continued and added; and
- Paragraph 9: Empire's Customer Programs Collaborative will be terminated, and Empire will utilize a Demand Side Management (DSM) advisory group, which shall not have voting rights.

Commercial and Industrial Facility Rebate and the Building Operator Certification. Empire's DSM regulatory asset also includes costs related to the Company's voluntary Interruptible Service Rider demand response program.

[67] 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.

[68] The effective date of the initial rates that reflect inclusion of Empire's Iatan 2 investment on customers' bills.

Attached to this Staff Report as Appendix 3, Schedule JAR-1 are pages from Staff's second Status Report on Energy Efficiency Advisory Groups and Collaboratives[69] which highlight the Empire DSM stakeholder group process and the challenges and successes to date of the Company's DSM programs. Schedule JAR-1 also includes a brief description, term, budget and comments concerning each of the Company's seven (7) DSM programs.[70] In addition to DSM programs described in Schedule JAR-1, Empire has: 1) a voluntary Interruptible Service Rider demand response program which was first implemented in 2009, and 2) Apagee HomeEnergy Suite and Commercial Energy Suite features added to its website with energy calculators and libraries that provide energy efficiency educational information to residential and commercial customers.

Staff Expert/Witness: John A. Rogers

b. Empire's DSM Cost Recovery Mechanism

Empire's Experimental Regulatory Plan included the following specific accounting and ratemaking treatment for Customer Programs costs[71]:

> 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 Experimental Regulatory Plan expired on June 15, 2011, the effective date of the initial rates that reflect inclusion of the Iatan 2 investment on customers' bills, as a result of

[69] On January 4, 2012, Staff provided to the Commission in File No. AO-2011-0035 its second annual Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives.

[70] Empire terminated its Residential CFL Program on December 31, 2010.

[71] (*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).

the Commission's June 1, 2011 *Order Approving Global Agreement* in Case No. ER-2011-0004. The *Global Agreement* specifies the following in it:

- Paragraph 13. d: Authorize continued amortization of the DSM regulatory asset for costs incurred during the Regulatory Plan for a term of 10 years. The costs of the DSM market potential study will be included in the regulatory asset; and
- Paragraph 13. e: Authorize an amortization for DSM program costs incurred after the end of the Regulatory Plan and prior to any program implementation under MEEIA for a term of six years.

Staff Expert/Witness: John A. Rogers

c. DSM Cost Recovery

Empire's Account 182318 contains costs of the Company's DSM programs that are in various stages of development and implementation. Staff participated in the previously authorized (and now expired) Customer Programs Collaborative (CPC) and participates in the current authorized DSM advisory group established to assist Empire in the development of DSM programs. From Staff's participation in these groups, as well as Staff's review of the costs in Account 182318, Staff has amortized the amounts incurred by Empire prior to the end of the its Regulatory Plan over ten years in accordance with the terms of the Commission's *Order Approving Global Agreement* in Case No. ER-2011-0004. Any amounts incurred after the end of the Regulatory Plan to date are amortized over a period of six years, per the *Global Agreement*. The DSM costs include the payments to Empire's customers that participate in the programs.

Staff Expert/Witness: Amanda C. McMellen

d. MEEIA

The Missouri Energy Efficiency Investment Act (MEEIA)was established in Senate Bill 376[72] and became law on August 28, 2009. The Commission's MEEIA rules[73] became effective May 30, 2011. With the passage of Senate Bill 376 and the enactment of the MEEIA, the State of Missouri has declared and directed the following:

[72] Section 393.1075, RSMo. Supp. 2010.

[73] The Commission's MEEIA rules include: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.

> 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.[74]

Subsections 393.1075.3 and 4, RSMo. Supp. 2010.

Staff Expert/Witness: John A. Rogers

e. Empire's Chapter 22 and MEEIA Filings

The Commission's June 27, 2012 *Order Approving Second Nonunanimous Stipulation and Agreement* in File Nos. EO-2011-0066 and EO-2012-0206 summarizes the status of Empire's initial and now-planned MEEIA filings as follows:

> On September 3, 2010, The Empire district Electric Company ("Empire") filed its 2010 Integrated Resource Planning Filing ("IRP"); File Number EO-2011-0066. The Commission accepted that plan when it approved an unopposed Nonunanimous Stipulation and Agreement, effective on April 27, 2012. That file was subsequently closed.
>
> On February 28, 2012, Empire filed an application seeking approval of demand-side programs and for authority to establish a Demand Side Management Investment Mechanism tracker; File Number EO-2012-0206. Since its filing, the parties have held numerous technical conferences.

[74] Subsections 393.1075.3 and 4, RSMo. Supp. 2010.

> On June 6, 2012, Empire, the Commission's Staff, the Office of the Public Counsel, the Missouri Department of Natural Resources, and Dogwood Energy, L.L.C. (collectively, the "Signatories") filed their Second Nonunanimous Stipulation and Agreement ("Second Agreement") in File Number EO-2011-0066. This filing re-opened this file, but the Second Agreement affects the outcome of File Number EO-2012-0206. Praxair, Inc., ("Praxair") and The Missouri Joint Municipal Electric Utility Commission (MJMEUC) have represented that they do not oppose the Second Agreement.
>
> Essentially, the Second Agreement provides that Empire will withdraw its pending Missouri Energy Efficiency Investment Act ("MEEIA") filing in File No. EO-2012-0206 and file a new application under the Commission's MEEIA rules after Empire makes its next Chapter 22 triennial compliance filing. The Signatories state that Empire is in the process of completing its required Demand-Side Management ("DSM") market potential study and that withdrawing its MEEIA filing will afford Empire the opportunity to complete its study and use the results of that study to provide for a comprehensive Chapter 22 triennial compliance filing, due on April 1, 2013, followed by a comprehensive MEEIA filing.

The following language from the *Second Nonunanimous Stipulation and Agreement* in File No. EO-2011-0066[75] provides a summary of the current agreement of Empire and parties concerning Empire's commitment to make its next MEEIA filing:

> 8. Empire renews its commitment to continue its current DSM programs until such time as a new MEEIA filing is approved, rejected or modified by the Commission with the agreement of Empire; and all Signatories agree not to propose any additional DSM programs or changes to Empire's existing DSM programs for implementation prior to such time as a new MEEIA filing is approved, rejected, or modified by the Commission with the agreement of Empire.
>
> 9. Empire agrees to meet with the parties to File Nos. EO-2011-0066 and EO-2012-0206 within 30 days of its Chapter 22 triennial compliance filing due April 1, 2013, to discuss any cost effective Realistic Achievable Potential (RAP) DSM portfolio contained in Empire's 2013 Preferred Plan pursuant to Chapter 22. Empire agrees to make its new MEEIA filing within 90 days of that meeting, unless agreed otherwise by the parties to File Nos. EO-2011-0066 and EO-2012-0206.

Staff Expert/Witness: John A. Rogers

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[75] See the Commission's June 27, 2012 *Order Approving Second Nonunanimous Stipulation and Agreement* in File Nos. EO-2011-0066 and EO-2012-0206.

7. Low Income Weatherization

a. Staff Recommendations

1. Annual funding continues at $226,430.
2. Expenditure guidelines and limits in tariff sheet No. 8c (Terms and Conditions 2.) be amended to state that expenditures on a home receiving weatherization will be consistent with U. S. Department of Energy (federal) guidelines.
3. Empire shall submit a revised tariff sheet No. 8c (*Promotional Practices Schedule, PRO*, E. *Weatherization Program*) to the Customer Program Collaborative (CPC) for comments no later than two weeks after the conclusion of this case and then file the revised sheet No. 8c with the Commission.

b. Program Design and Development

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), provided special funding of $128 million for the Missouri Weatherization Program for the period of April 2009 – March 2012 ("ARRA Period"). The ARRA provided 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 made a concerted effort to utilize the ARRA funding before the

March 2012 deadline. Subsequently, for 2012 program year Missouri received no significant federal funds for Weatherization.

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 unspent funds. Consequently, for the final Regulatory Plan Weatherization Program Year, 2010-2011, Empire reallocated the unspent funds to Weatherization Program fund for use by the Weatherization Agencies and extended the 2010-2011 program's period from twelve months to fifteen months ending in December 2011 (Appendix 3, Schedule HEW-1).

c. Program Evaluation

The Weatherization Program was evaluated and the results presented in the report, *An Evaluation of the Low-Income Weatherization Program, Results of an Impact Evaluation*.[76] 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 the inclusion of compact fluorescent lights (CFLs) 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. Subsequent to the ARRA period, the Weatherization Agencies are using surplus Empire and other utility funds to help provide for a higher level of weatherization activity than before ARRA.

d. Conclusion

Given the positive evaluation of the Empire Weatherization Program by an independent evaluator, the Company's ability to see that funding is utilized by the Weatherization Agencies, and the inclusion of CFL's as an additional measure in the Weatherization program, Staff supports Empire's annual budget of $226,430 for calendar year 2013. This coincides with the

[76] Prepared for Empire by Johna Roth, TedMarket Works, Oregon, WI, March 16, 2009.

Weatherization Program as agreed to in rate case No. ER-2011-0004. The allocation of these funds among the Weatherization Agencies by the process contained in the Weatherization Program tariff sheet No. 8c is also in agreement with the Stipulation and Agreement in Case No. ER-2011-0004. Because it is an energy efficiency program, recovery of Weatherization Program expenditures should be in the same method as set forth in the Commission Orders in Case No. ER-2011-0004[77] and Case No. EO-2011-0066,[78] which acknowledge the current Empire resource plan. It is anticipated that Empire's low income weatherization program will also be addressed in its next Resource Plan scheduled to be filed in 2013, however Staff recommends that a revised tariff sheet No. 8c be submitted to the CPC for comments then filed with the Commission after the conclusion of this rate case to change the expenditure average and upper limit per customer to be consistent with current federal weatherization guidelines. Some additional revisions to the tariff sheet are needed to update the program consistent with the Commission Order in this case.

Staff Expert/Witness: Henry E. Warren, PhD

8. Current and Deferred Income Tax

a. Current Income Taxes

Current income tax for this case has been calculated by the Staff largely consistent with the methodology used in Empire's most recent rate case, Case No. ER-2011-0004. 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

[77] *Order Approving Global Agreement*, Attachment A, Paragraph 13 (d) authorizes the "…continued amortization of the DSM regulatory asset for costs incurred during the Regulatory Plan for a term of 10 years." Paragraph 13 (e) authorizes "…an amortization for DSM program costs incurred after the end of the Regulatory Plan and prior to any program implementation under MEEIA for a term of six years."

[78] *Order Approving Nonunanimous Stipulation And Agreement and Accepting Integrated Resource Plan*, Appendix A, Paragraph 9 (e) states "[i]n the event the cost recovery provisions of the MEEIA rules are not in effect, the parties will support a reasonable request for an Accounting Authority Order authorizing the Company to accumulate the costs associated with new demand-side programs in regulatory asset accounts as the program(s) costs are incurred, unless a mechanism concerning these costs is established in File No. ER-2011-0004. The amortization of these deferred program costs and the recovery of these deferred program costs from the Company's customers, if not later addressed by a DSIM, shall be addressed in the Company's subsequent electric general rate proceeding."

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 Empire's current income tax liability. The composite tax rate taking into account both federal and state income tax rates 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.

Staff has reflected for income tax expense a tax deduction that is related to the Employee Stock Option Plan (ESOP) in the cost of service calculation. Empire receives a tax deduction for the dividend it pays on the stock held in its ESOP. A significant portion of this stock is the result of contributions made by Empire employees. The compensation that is paid to these employees, including the amount that the employee contributes, as well as the amount that Company matches to the 401 (k) plan, is included in Empire's cost of service. Therefore, Staff asserts that it is appropriate to adjust the level of income tax expense to reflect this deduction.

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
- Non-Deductible Expense
- Contributions In Aid of Construction
- Book Amortization

Subtractions from Operating Income:

- Interest Sync
- Tax Depreciation - Straight-Line
- Tax Depreciation-Excess
- Employee Stock Option Deduction (ESOP)

Staff Expert/Witness: Paul R. Harrison

b. Deferred Income Taxes

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 Internal Revenue Service (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 (TRA) 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 TRA: Enactment of the TRA created excess deferred tax amounts associated with depreciation timing differences. As such, an amortization is used to return excess deferred taxes resulting 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

c. State Income Tax Flow-Through

On Staff Accounting Schedule 2, Calculation of Provision for Income Taxes, of the Company's workpapers that support its twelve-months ending March 31, 2012 Filing, Empire included an adjustment to increase its income tax expense associated with an amount of state income tax allegedly flowed through to customers in Empire Missouri rate proceedings prior to August 15, 1994. However, Empire did not support this adjustment in its Direct Testimony. Staff has not included an adjustment for this expense in its direct cost of service and it should not be recovered in rates.

Staff Expert/Witness: Paul R. Harrison

9. Regulatory Plan Amortization Impacts

In Case No. EO-2005-0263, the Commission approved an Experimental 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 such measure was allowing Empire to collect "regulatory plan amortizations" in rates, under certain circumstances, so that Empire would receive a greater amount of rate relief than it would normally receive under traditional cost of service regulation. Empire was awarded an amount of regulatory plan amortizations in rates in Case Nos. ER-2006-0315, ER-2008-0093, and ER-2010-0130. In Case No. ER-2011-0004, as the Iatan 2 generating station was placed in service and Empire's Regulatory Plan came to an end, Staff removed the cumulative additional amortizations from its calculation of Empire's expenses. The additional amortizations ceased when the new rates went into effect as a result of that proceeding. The rates set in Case No. ER-2011-0004 went into effect June 15, 2011. The test year in this case is the twelve months ending March 31, 2012, thus 2.5 months of the amortization were included in the test year in Account 403. Staff has made an adjustment of ($3,013,236) to remove the amortization from test year. The Regulatory Plan amortizations accumulated from previous cases are now reflected within the accumulated depreciation reserve.

Staff Expert/Witness: Kimberly K. Bolin

10. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of their customers) associated with unanticipated losses. Staff made an adjustment to annualize Empire's insurance expense to reflect the premiums paid as of June 30, 2012, the end of the update period.

Staff Expert/Witness: Casey Wolfe

11. Bad Debt Expense

Bad debt expense is the portion of retail revenue that Empire is unable to collect from retail customers due to non-payment of bills. 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. Staff examined the actual five-year (2007-2012) 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 consistent upward or downward trend in this item. From the information provided through March 31, 2012, a five-year uncollectable percentage was calculated, 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: Jermaine Green

12. Postage

Staff annualized Empire's test year postage expense to reflect the postal increase that went into effect on January 22, 2012.

Staff Expert/Witness: Casey Wolfe

13. PSC Assessment and Rate Case Expense

Staff has included the actual costs incurred by Empire for rate case expense as of October 31, 2012, directly related to this case (No. ER-2012-0345). 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.

Staff removed from Account 928, Regulatory Commission Expense, all expenses booked in the test year associated with prior Empire Missouri rate proceedings. Staff has made a separate adjustment to add rate case costs associated with the current rate proceeding to Account 928; this adjustment includes an "add back" of the adjusted costs booked to Account 928 for Federal Energy Regulatory Commission (FERC) expenses and the PSC annual assessment.

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

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. Staff has normalized the included rate case expense over a two (2) year period.

In this case, Staff reviewed Empire's projected and actual rate case expense amounts based upon the traditional criteria of allowing rate recovery of all reasonable and prudent expenses, normalized over an appropriate period of time.

The Commission issued an Order in April 2011 establishing a docket (Case No. AW-2011-0330) to conduct a review of its policies regarding recovery of rate case expense in rates. In response, Staff recently filed a draft version of a report concerning its recommendations for future treatment of rate case expense in Case No. ER-2012-0166, Ameren Missouri's current rate proceeding before the Commission. Staff expects to file a final version of its rate case expense report shortly. The position of Staff regarding recovery of rate case expense may change in future rate proceedings based upon the content and recommendations contained within the final rate case expense report.

Staff Expert/Witness: Casey Wolfe

14. Injuries and Damages and Workers' Compensation

Empire maintains workers' compensation insurance for the benefit of its employees. Staff's workers' compensation adjustment annualizes this expense based upon the premiums in effect at June 2012 to reflect an ongoing and normal expense level for Empire.

From time to time, Empire is sued by claimants seeking payment of damages. If Empire loses the lawsuit, it is likely to be required to make a payout to the aggrieved party. Alternatively, it may choose to enter into an out-of-court settlement, also resulting in a pay-out. Based upon generally accepted accounting standards, Empire is required to charge to current expense an estimate of its future payouts for injuries and damages claims. To determine a normalized level of this expense, Staff used a five-year average of actual injuries and damages payments instead of relying upon accounting estimates. A five-year average of payments was used because a historical analysis shows a considerable fluctuation in the annual amount of payments.

Staff Expert/Witness: Casey Wolfe

15. Advertising Expense

Empire engaged in advertising activities during the test year. Staff recommends recovery through rates of a level of expense related to advertising that is beneficial to ratepayers. In making its recommendation of the allowable level of Empire's advertising expense, Staff relied on the principles the Commission relied upon regarding KCPL in Case Nos. EO-85-185, et al.[79] The Commission recognized five categories of advertisements, and specified rate treatment for each of the following categories:

1. General: informational advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;

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

3. Promotional: advertising used to encourage or promote the use of electricity;

4. Institutional: advertising used to improve the company's public image;

5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements and provided the rationale that a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement.

Following this guidance, Staff's adjustment excludes promotional and institutional advertising expenses from recovery in rates, in the amount of $56,967.

Staff Expert/Witness: Jermaine Green

16. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed. Staff reviewed Empire's test year outside services expense booked to Accounts 923.045 through 923.047. Staff normalized the amounts of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts in the amount of $901,918. This adjustment does not include outside services related to rate case expense. Outside services incurred for rate case purposes are booked in a separate account.

Staff Expert/Witness: Jermaine Green

17. Dues and Donations

Staff reviewed the list of membership dues paid, and donations made, to various organizations that Empire charged to its utility accounts during the test year. Staff recommends adjustments to exclude various dues and donations that were included by Empire in its above-the-line expense accounts. In *Re: Missouri Public Service, a Division of UtiliCorp United, Inc.*, Case Nos. ER-97-394, et al., Report and Order, 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

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

Staff excluded dues and donations that do not have any direct benefit to ratepayers and were not necessary for the provision of safe and adequate service. Allowing Empire to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues excluded from recovery in the rate case are dues paid to the Home Builders Association, Rotary Club, and Twin Hills Golf and Country Club, etc. Examples of donations that were excluded include donated merchandise purchased from Wal-Mart Inc. Area Chamber of Commerce dues were allowed, but National and State Chamber of Commerce dues were disallowed as being duplicative costs to the local Chamber of Commerce organizations.

Staff Expert/Witness: Jermaine Green

18. EEI Dues

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

In Case No. ER-83-49, a KCPL rate increase case, the Commission stated its determination that EEI dues:

> …would be excluded as an expense until the company could better quantify the benefit accruing to both the company's ratepayers and shareholders.

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

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

> . . . The argument that allocation is not necessary if the benefits lessen the cost of service to the ratepayers by more than the cost of the dues, misses the point.

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

Empire failed to quantify ratepayer and shareholder benefits from its participation in EEI; therefore, the Staff removed EEI dues in the amount of $119,808 from Empire's cost of service.

Staff Expert/Witness: Jermaine Green

19. Tree Trimming Expense

In Case No. ER-2008-0093, the Commission authorized Empire to set up a two-way tracker mechanism to account for any difference between Empire's incurred vegetation management (i.e., tree trimming) and infrastructure inspection costs compared to an estimated target annual amount of $8,575,000. In the *Non-Unanimous Stipulation and Agreement* and the *Global Agreement* filed in the last two rate cases, File Nos. ER-2010-0130 and ER-2011-0004 respectively, Staff and the Company agreed to continue the vegetation tracker. The *Non-Unanimous Stipulation and Agreement* in File No. ER-2010-0130 terminated the infrastructure tracker approved in the 2008 rate case. In File No. ER-2011-0004, Staff proposed adjustments to expense to amortize the File Nos. ER-2008-0093, ER-2010-0130 and ER-2011-0004 accumulated tracker asset over a five-year period, in the amount of $661,102. In the current case, File No. ER-2012-0345, Staff adjusted expense to amortize the tracker asset over a five-year period, in the amount of $1,503,719.

Per the terms of the *Non-Unanimous Stipulation and Agreement* and the *Global Agreement* in File No. ER-2010-0130 and ER-2011-0004, respectively, the signatories agreed to continue the vegetation management tracker until at least Empire's next Missouri rate proceeding following its "Iatan 2" case, and the estimated target annual amount was changed from $8,575,000 to 9 million dollars in File No. ER-2010-0130. In this case, File No. ER-2012-0345, based upon its analysis of Empire's ongoing vegetation management costs, Staff is recommending that the vegetation management tracker continue and that the tracker base amount be changed from 9 million dollars to 12 million dollars. Staff has adjusted its cost of service to include the additional funds for vegetation management in this case.

In File No. ER-2011-0004, Empire proposed to recover certain "remediation" costs through the vegetation/infrastructure tracker. These remediation costs were 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 this case, the Company requested 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. Staff reviewed these costs in this case and has annualized these incurred non-labor remediation costs to increase expense in the amount of $303,337.

Staff has also included in its case an addition to Rate Base in the amount of the adjusted vegetation and infrastructure tracker regulatory asset balance as of June 30, 2012. (*see* Section VI. N.).

Staff Expert/Witness: Paul R. Harrison

20. SWPA Amortization

As described previously in this Report, in Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to the customers over a ten year period via a tracker mechanism. This yearly amortization, unlike other amortizations discussed in this Report, does not increase the Company's expense levels but is a reduction or offset to expenses. The test year did not include a full year of amortization, so an adjustment of $118,163 (Missouri jurisdictional) to was made to reflect a full year of amortization for this item.

Staff Expert/Witness: Kimberly K. Bolin

21. Banking Fees

Staff made an adjustment to annualize the cost associated with banking fees paid by the Company for its commercial lines of credit. The Company renegotiated its Unsecured Credit Agreement ("Agreement") in January 2012. Staff, therefore, annualized the cost of the Agreement based upon the current expenditures for the bank line of credit as provided by the Company in its workpapers supporting its direct filing. An offsetting adjustment was made to the cost of these banking fees by the amount of interest earned on overnight investments made by the Company during the test year. This methodology is consistent with the Staff's approach to this issue in past rate cases.

Staff Expert/Witness: Amanda C. McMellen

22. Lease Expense

Lease costs are those costs incurred by Empire for the leasing of its equipment and office space. The Staff examined these costs for the test year, updated through June 30, 2012, and made an adjustment to annualize these costs in rates.

Staff submitted Data Request No. 0077 to Empire asking for a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri electric operations, along with the lease costs and information concerning all changes to the lease amounts since the beginning of the test year (April 1, 2011). Staff used the information provided in this response to adjust Empire's lease expense to an annualized level.

Staff Expert/Witness: Amanda C. McMellen

23. Pay Station Fees

When a customer pays their electric bill at a third party pay station, Empire must remit a fee related to this payment. Empire is requesting that the each individual customer should be responsible for paying this fee as incurred. Staff does not oppose the requested adjustment of ($69,500) to eliminate the expenses related to third party pay stations.

Staff Expert/Witness: Amanda C. McMellen

24. Tornado AAO Amortization

The Commission issued an order on November 30, 2011, that approved and incorporated the *Stipulation and Agreement* in Case No. EU-2011-0387. In this *Stipulation and Agreement*, the parties to that case agreed to allow Empire to defer to Account 182.3, Other Regulatory Assets, incremental operations and maintenance expenses associated with repair, restoration and rebuild activities associated with the May 22, 2011, tornado, and depreciation and carrying charges equal to its ongoing Allowance for Funds Used During Construction rates associated with tornado-related capital expenses. The Company agreed that if it filed a general rate case in

Missouri by June 1, 2013, then Empire would begin to amortize the deferral balance beginning on the earlier of: 1) the effective date of new rate implemented in its next general rate increase case or rate complaint case; or 2) June 1, 2013.

As of June 30, 2012, Empire had deferred $2,266,587 in Account 182 for tornado-related expenses. Staff has made an adjustment to include an annual amortization of $226,659 in its cost of service.

Staff Expert/Witness: Kimberly K. Bolin

IX. 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 TWT-1 through TWT-4 attached to the prefiled direct testimony of Company witness Todd W. Tarter. 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 with the exception heat rate testing, as discussed below. In addition, Empire did not provide a line loss study as required by 4 CSR 240-20.090(9). According to the response in Data Request No. 0208, the Company is expected to provide its line loss study as soon as it becomes available. Staff will address the line loss study and heat rate testing as appropriate, but the information provided at the time this rate case was filed was deficient.

Staff recommends that the Commission order that the Company's FAC tariff sheets 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;
2. Include Base Cost Factors in the FAC tariff sheets calculated from the Base Costs in the true-up total revenue requirement in this rate case to assure that the Company does not over- or under-collect as a result of the Base Cost used to calculate the Base Cost Factors in the FAC not matching with the Base Costs used to set permanent rates in this general rate case;

3. Standardize the terminology in Empire's FAC tariff sheets to be consistent with changes Staff is recommending, when appropriate, for the FACs of the three investor-owned electric utilities with FACs. Staff's recommended changes to Empire's FAC tariff sheets will be provided in the Class Cost-of-Service/Rate Design Staff Report to be filed on December 13, 2012;
4. Clarify that the only transmission costs that are included in Empire's FAC are those that Empire incurs for purchased power and off-system sales ("OSS");
5. Clarify that the Renewable Energy Credit ("REC") costs be excluded from Empire's FAC; and
6. SO_2 allowance revenues be included in Empire's FAC as an off-set to fuel and purchased power costs.

Staff will provide exemplar FAC tariff sheets to reflect these changes as part of its Class Cost-of-Service and Rate Design testimony on December 13, 2012. Further, Staff recommends that the Commission order Empire to continue to provide or make available additional information and documents (as detailed later herein) to aid the Staff in performing FAC rate adjustment, prudence, and true-up reviews.

At this time Staff does not have its estimate for the Base Energy Cost per kWh,[80] but will provide it when Staff files its Class Cost of Service and Rate Design Report on December 13, 2012. Staff will use the Base Costs and kWh from its fuel run to develop the appropriate Base Cost Factors ("Base Cost Factors") in its Class Cost-of-Service and Rate Design Report.

1. History

Senate Bill 179[81] ("SB 179") was passed and enacted in 2005. It authorized investor-owned electric utilities to file applications with the Commission requesting authority to make periodic rate adjustments outside of general electric rate proceedings for their prudently-incurred fuel and purchased power costs. SB 179 granted the Commission the

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[80] Base Cost is defined in Empire's current tariff sheet 17h as "Base energy cost per kWh at the generator, established in the most recent base rate case. The base energy cost per kWh is $0.02823 for each accumulation period." Base Cost is also defined on tariff sheet 17i as a dollar amount calculated as follows:

1. For each accumulation period B = (NSI kWh * $0.02823)

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.

[81] Section 386.266, RSMo. 2010 Cum. Supp.

authority to approve, modify, or reject the electric utility's request. SB 179 also stated that the rate schedules implementing these rate adjustments outside of the rate case may provide the electric utility with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities.

Prior to the passage of SB 179, fuel and purchased power costs were estimated and included in the determination of the utility's revenue requirement in general electric rate proceedings. If the electric utility managed its fuel and purchased power procurement activities in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the general electric rate proceeding, the savings were retained by the electric utility. If actual fuel and purchased power costs were greater than the cost included in the revenue requirement in the general electric rate proceeding, the electric utility absorbed the increased cost.

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 with an effective date of September 1, 2008. In Empire's 2010 general rate case, Case No. ER-2010-0130, and 2011 general rate case, Case No. ER-2011-0004, the Commission authorized continuation, with modifications, of Empire's FAC. The primary features of Empire's present FAC (tariff sheet numbers 17 through 17k) 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;
- Fuel Adjustment Rate ("FAR") previously known as Cost Adjustment Factor ("CAF") filings annually not later than April 1 and October 1;
- One Base Energy Cost per kWh factor: one for all calendar months of the year.
- A 95%/5% sharing mechanism;
- FAR 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 FAR for a subsequent recovery period.

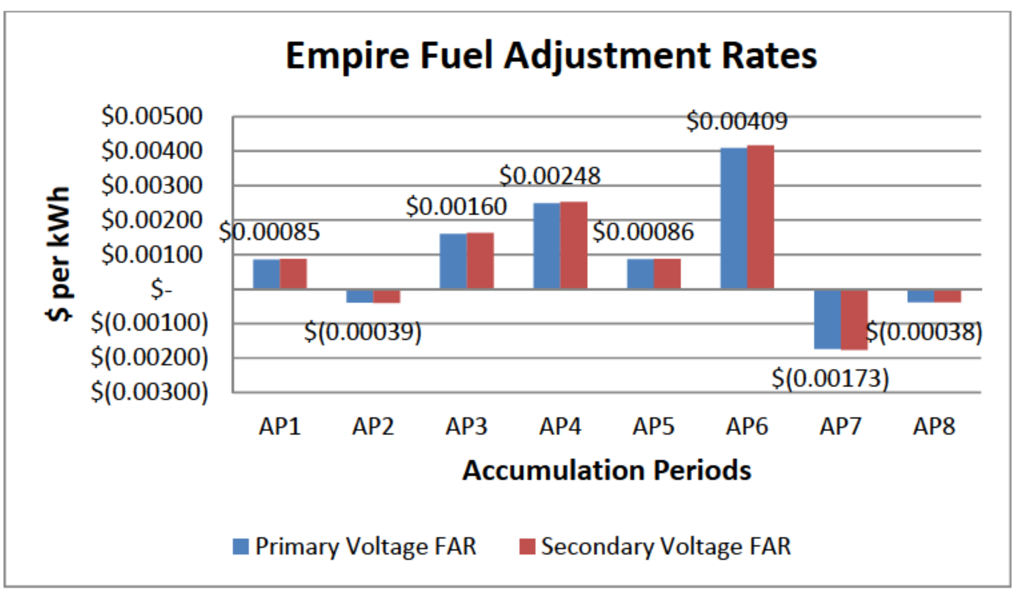
Empire has made eight FAR filings (File Nos. EO-2009-0349, ER-2010-0105, ER-2010-0275, ER-2011-0095, ER-2011-0320, ER-2012-0098, ER-2012-0326, and ER-2013-0122). The resulting changes to the Empire FAR ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The Base Cost Factors were originally set in Empire's 2008 general rate case and were changed as a result of the settlement of Empire's 2010 and 2011 general rate cases.

Staff has filed two prudence review reports (File Nos. EO-2010-0084 and EO-2011-0285) 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 periods reviewed. Staff has begun conducting Empire's third prudence review (File No. EO-2013-0114) and is expected to file its report February 26, 2013.

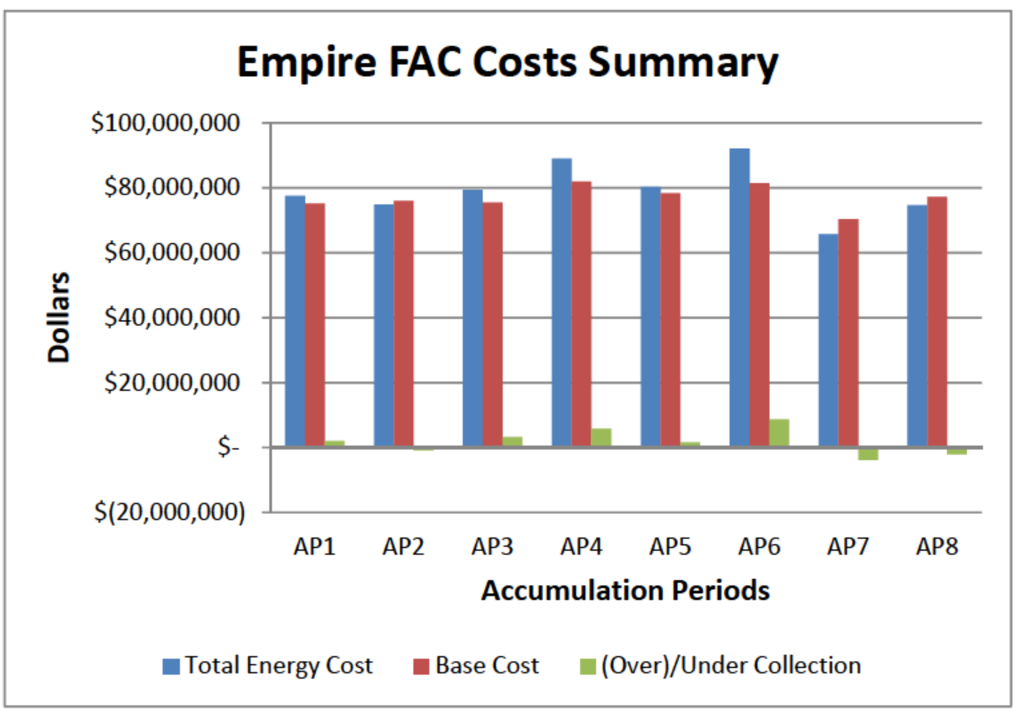
2. Continuation of FAC

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

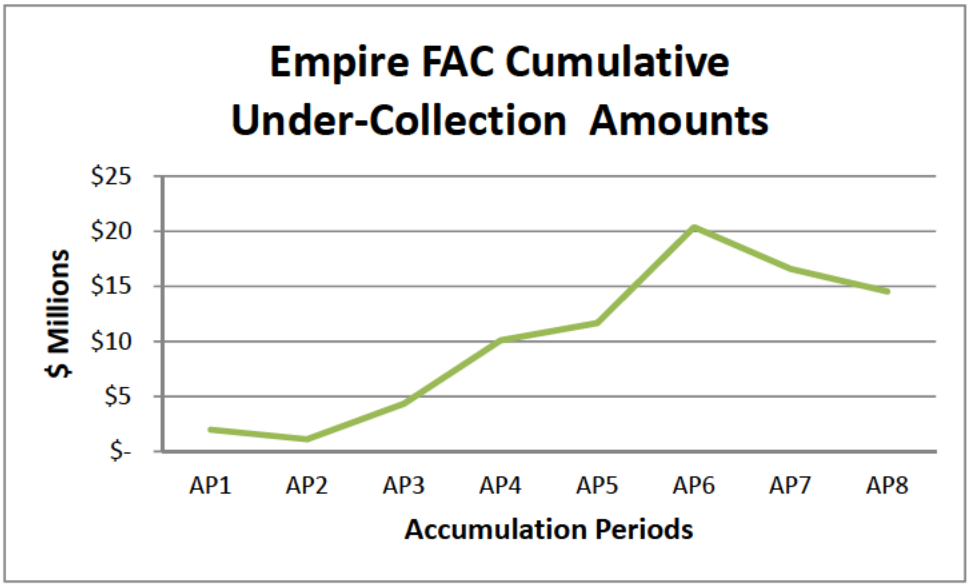
The Company has filed for and received approval of changes to its FARs for eight completed accumulation periods (AP1 through AP8). The primary and secondary voltage FARs for each accumulation period are reflected in the following chart:

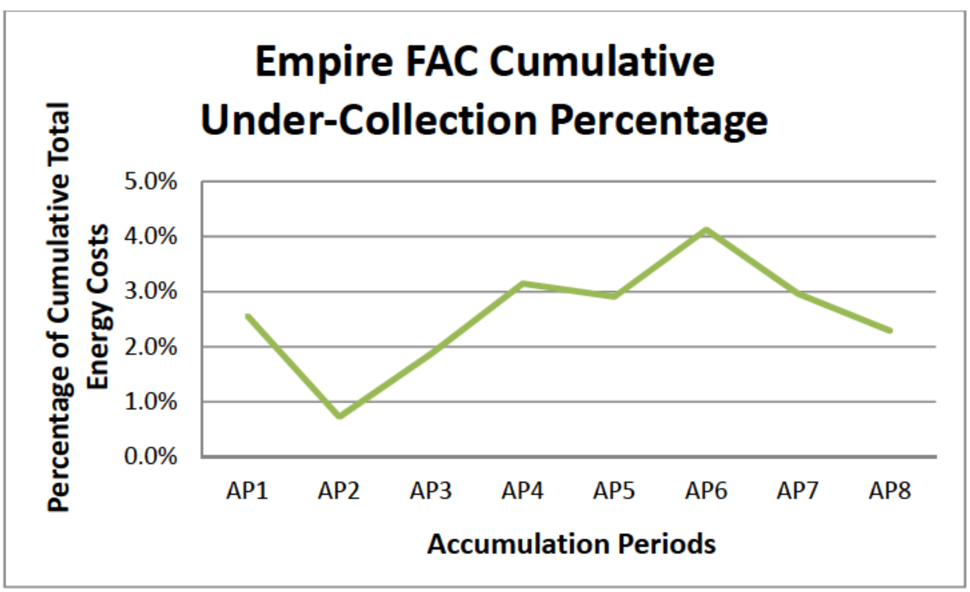


The Company's total energy costs in each accumulation period have exceeded the then-effective Base Cost Factors multiplied by monthly usage billed to Empire's customers' in five out of eight completed accumulation periods. Total energy costs include: Empire's total booked costs as allocated to its Missouri retail jurisdiction for fuel consumed in the Company's 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. Total energy costs do not include the purchased power demand costs. These costs are off-set by off-system sales revenues, any emission allowance revenues collected, and renewable energy credit revenues. During AP2, AP7, and AP8, Empire's Base Cost Factors multiplied by customer usage in the appropriate months or each accumulation period exceeded total energy cost; 95% of the difference was returned to customers during recovery periods 2, 7, and 8. The following chart illustrates Empire's total energy costs, the then-effective Base Cost Factors in the FAC tariff multiplied by the monthly kWhs during accumulation periods and the difference between them - the "over/under collection" amounts - for each of the eight accumulation periods:



The next two charts illustrate the following information for the first eight accumulation periods: 1) cumulative amount of the differences between total energy costs and the Base Cost Factor 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 Factor in Empire's FAC tariff sheets multiplied by the kWh usage in the accumulation period:





From the above information, Staff observes that the FAC cumulative under-collected amount over eight years is $14.5 million (2.3 percent of total actual energy costs of $634 million).

3. Sharing Mechanism of FAC

Staff proposes changing Empire's current 95%/5% FAC sharing mechanism to an 85%/15% FAC sharing mechanism. 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, stating 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 eight accumulation periods with the current 95%/5% sharing mechanism, and with several other selected sharing mechanisms including both 95%/5% and 85%/15%, are shown in the chart below. Staff proposes changing the current 95%/5% FAC sharing mechanism to an 85%/15% sharing mechanism.

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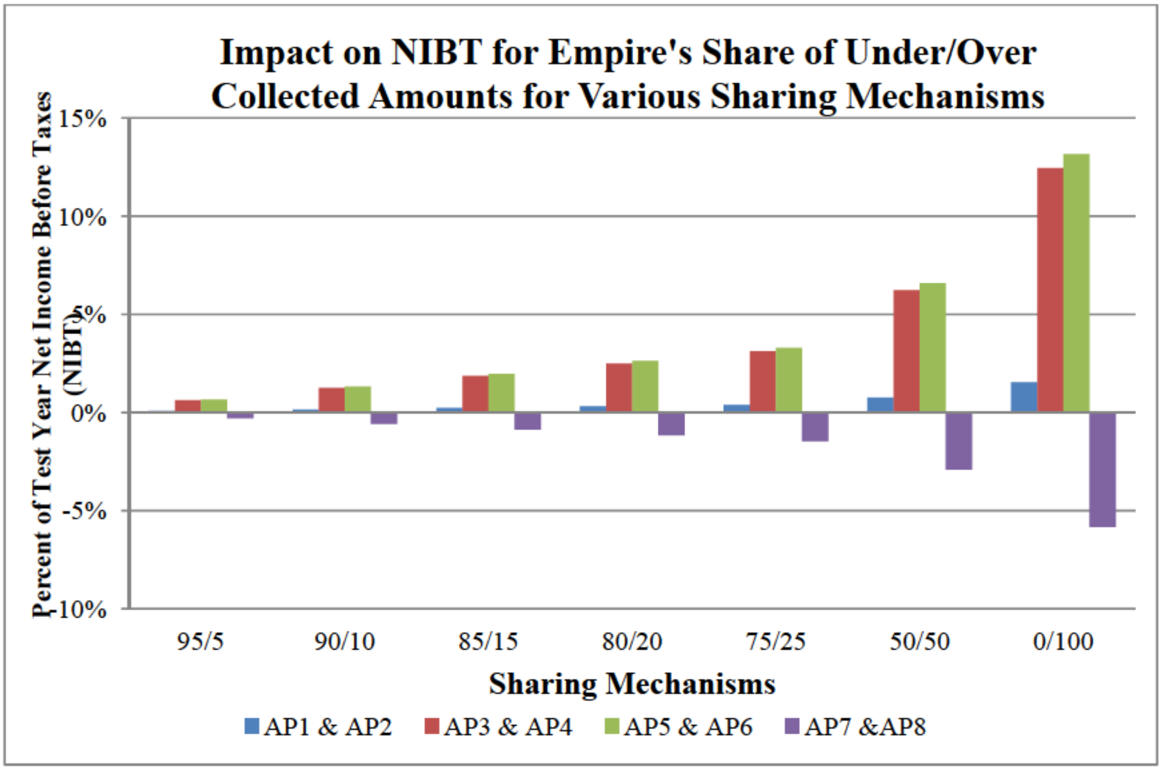
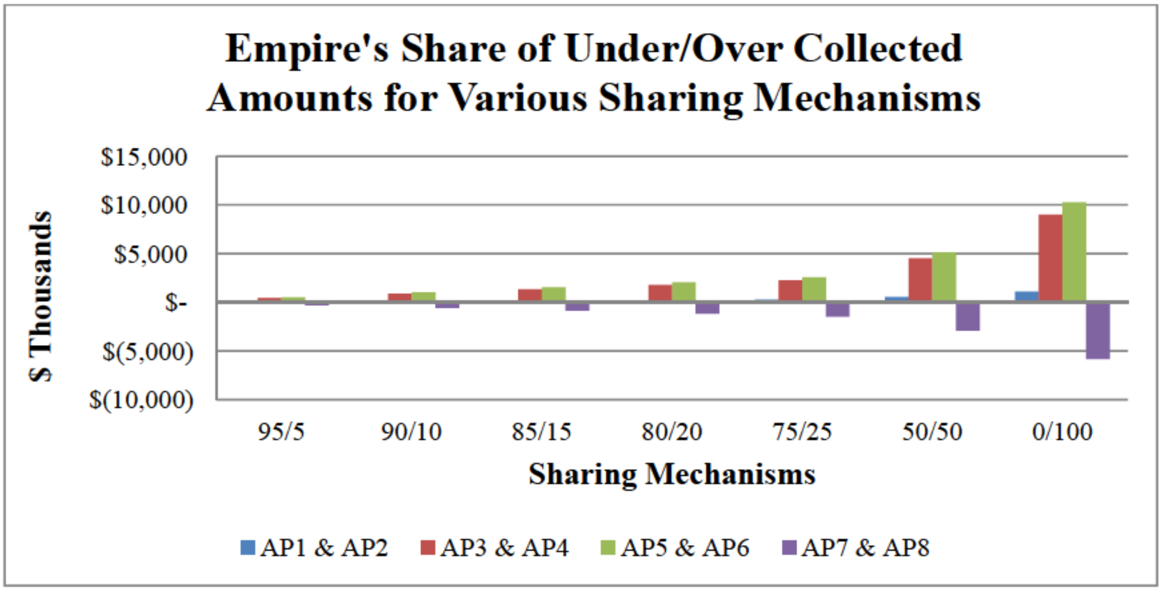


Through this analysis Staff determined that Empire's 5% share of the total under-collection amount of approximately $14.5 million during the first eight accumulation periods is $726,381 and represents 0.22% of the test year net income before taxes ($323 million). All else remaining the same, the under-collection during the first eight recovery periods would have been 0.9% for the Staff's proposed 85%/15% sharing mechanism. Similarly, Staff estimates that for Company shares of 10%, 20%, 25%, 50%, and 100% of the total under-collection amount during the first eight accumulation periods represent approximately 0.5%, 0.9%, 1.1%, 2.3%, and 4.5% 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 $14.5 million during the first eight accumulation periods that the Company would have been responsible for if the Company's share had been 5%, 10%, 15%, 20%, 25%, 50%, and 100% is illustrated in the following chart.



Staff recommends an 85%/15% sharing mechanism, which, all else remaining the same, for the first eight accumulation periods would have resulted in the Company being responsible for an average of $544,786 annually of the under-collected amount of the FAC. Measured differently, this is approximately 0.7% of test year net income before taxes and 0.3% of Empire's total energy costs during that same period. At a 15% share of FAC over/under collection amounts, Empire begins to take on a more meaningful portion of the risk of actual FAC costs and revenues. 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 and to increase revenues from off-system sales, RECs and emission allowances. Also, Empire experienced an over-collection in AP2, AP7 and AP8. Empire would have kept a larger part of the over-collection, if it had a different sharing mechanism, such as 85%/15% that Staff is recommending.

Staff notes that before the Commission authorized Empire's FAC, Empire was responsible for 100% of fuel and purchased power cost variations between general rate case filings. With the Commission's 2008 authorization of Empire's FAC, 95% of the responsibility or any over/under collection of total energy costs shifted from the Company to its customers. An 85%/15% sharing mechanism more appropriately balances the risk and interest between the shareholder and ratepayer than the current sharing mechanism.

4. Base Energy Cost Per kWh

When calculating the base energy cost per kWh rate that will be multiplied by Net System Input kWh to equal Base Energy Cost, there are three factors that off-set the fuel and purchased power costs:

1. Off-system sales revenues;
2. Renewable Energy Credit revenues; and
3. SO2 allowance revenues.

Since Empire's FAC was approved by the Commission in File No. ER-2008-0093, off-system sales revenues have not been included in the base energy cost per kWh rate[82], but the actual revenues have been flowing through the FAC. This meant that Empire kept 5% of all off-system sales revenues. Off-system sales revenues have not been included in the base energy cost per kWh rate, because they have been minimal and the amount of revenues has been inconsistent. Staff again recommends excluding off-system sales revenues from the base energy cost per kWh rate for Empire since the revenue amount is still minimal and have still been inconsistent since Empire's last rate case. Also, the Southwest Power Pool market will be starting in the near future, and it is not known at this time how that will impact Empire's off-system sales revenues.

In Empire's last rate case, Case No. ER-2011-0004, REC revenues were included in the base energy cost per kWh rate, but not the REC costs. Staff notes that Empire is not recommending that REC costs be included in the base energy cost per kWh rate in the FAC. Staff still recommends that REC costs be excluded from the base energy cost per kWh rate in Empire's FAC, since Empire is only required to have RECs to meet the Renewable Energy Standard (RES), and because it would be contrary to the Commission's Rule on Electric Utility Renewable Energy Standard Requirements, 4 CSR 240-20.100, to flow the costs associated with RECs through the FAC. 4 CSR 240-20.100(6)(A)16 provides that "*RES compliance costs* shall only be recovered through an RESRAM or as part of a general rate proceeding and *shall not be considered for cost recovery through* an environmental cost recovery mechanism or *fuel adjustment clause* or interim energy charge." (emphasis added). Staff is including the REC

[82] Base energy cost per kWh at the generator, established in the most recent base rate case.

costs in its revenue requirement because the sale of a REC will generate revenue to off-set fuel and purchased power costs that will benefit the ratepayer.

Staff included SO_2 allowance revenues in its revenue requirement and in the base energy cost per kWh rate in Empire's FAC. Any revenues that Empire makes from the sale of a SO_2 allowance will flow through the FAC as an off-set to fuel and purchased power costs, which will benefit the ratepayer. This will assure that the ratepayers receive 95% of any sale of SO_2 emission allowances.

5. Changes to FAC Tariff Sheet Terminology

The Commission, Staff and the Company have been refining FACs and the tariff sheets that implement them since the Commission first authorized Aquila, Inc. n/k/a KCP&L Greater Missouri Operations Company ("GMO") to use a FAC in Case No. ER-2007-0004. While each electric utility's FAC complies with the same Commission rules, each electric utility has unique FAC tariff sheets with unique acronyms and definitions. Different nomenclature for the same thing is used across the utilities and sometimes even within a single utility's tariff sheets. For example, the dollar amount of the adjustment is referred to in GMO FAC tariff sheets as the "Fuel Adjustment Clause (FAC)," "Fuel and Purchased Power Adjustment," "FPA," "FAC costs," and just "FAC." Empire refers to it as "FAC" and "Fuel Adjustment Clause." The adjustment is only referred to in Union Electric Company d/b/a Ameren Missouri's ("Ameren Missouri") tariff sheets as the "Third Subtotal." Staff proposes that the dollar amount of the adjustment be referred to uniformly for all electric utilities as the "Fuel and Purchased Power Adjustment" or "FPA." Staff made this same recommendation in the pending Ameren Missouri rate case, File No. ER-2012-0166 and GMO's pending rate case, File No. ER-2012-0175.

This is just one of many "clean-up" changes that Staff will recommend in its Class Cost-of-Service/Rate Design Report to be filed in this case on December 13, 2012. Staff has been working with all of the electric utilities, including Empire, on these proposals and hopes to come to a consensus on the terminology to be used within the electric utility industry in Missouri. It is not Staff's intent to change the meaning of different phrases in each utility's FAC tariff sheets, but to help avoid and minimize confusion when discussing the FACs of electric utilities in Missouri.

6. Additional Reporting Requirements

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 Case No. ER-2010-0130, and in the 2011 general rate case, Case No. ER-2011-0004:

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: Matthew J. Barnes

B. Heat Rate Testing Review

If an electric utility requests that a Rate Adjustment Mechanism (Fuel Adjustment Clause (FAC)) be continued or modified, Commission Rule 4 CSR 240-3.161(3)(Q) requires that an electric utility shall file specific information as part of its direct testimony in a general rate proceeding:

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

The Commission authorized Empire's FAC in Case No. ER-2008-0093. The FAC was continued in Case No. ER-2010-0130 and Case No. ER-2011-0004. Empire has requested the FAC be continued in the current general rate proceeding, Case No. ER-2012-0345.

Company witness Todd W. Tarter filed the results of the most recent heat rate/efficiency tests for the Company's generating units. Staff has reviewed the summary results of those tests and compared the results with the summary results from the previous general rate proceedings.

With the exception of the Asbury and State Line Combined Cycle (SLCC) units, all generating units were tested within the previous 24 months, based on the filed data for the current general rate proceeding. Summary data for Asbury and SLCC was provided but was completed in June of 2010, which is the month before the 24 month period in question. Staff was provided with new heat rate tests results for Asbury, SLCC, and Riverton 7&8 on November 30, 2012, but has not completed its review of these tests. Staff will file additional testimony on this matter when the review of the Asbury and SLCC heat rate tests is completed.

The heat rate/efficiency testing information for all other generating units appears to be reasonable. Staff would note that Company witness Tarter's Schedule TWT-6 refers to the KCPL filing for the results of Iatan 1 & 2 generating units but since KCPL does not have an FAC, the correct reference would be Case No. ER-2012-0356, GMO's current rate proceeding.

Staff Expert/Witness: Daniel I. Beck

X. Miscellaneous

A. Energy Independence and Security Act (EISA)

On December 19, 2007, the Energy Independence and Security Act of 2007 ("EISA"), which amended various sections of the Public Utility Regulatory Policies Act of 1978 ("PURPA")[83], was signed into law. PURPA's purposes are to encourage: 1) conservation of electric energy, 2) efficiency in the use of facilities and resources by electric utilities, and

[83] Appears generally in 16 U.S.C. Section 2601, et seq. However, various provisions appear elsewhere in the United States Code.

3) equitable rates to consumers of electricity.[84] EISA established four additional PURPA standards for electric utilities as follows: Integrated Resource Planning (IRP), Rate Design Modifications to Promote Energy Efficiency Investments, Consideration of Smart Grid Investments, and Smart Grid Information.[85]

On December 15, 2008, Staff filed requests for the Commission to open dockets for the purpose of establishing records for consideration and determination as to whether it is appropriate to implement the new standards encompassed within EISA to carry out the above noted purposes. EISA establishes timeframes within which the Commission is to perform this consideration and determination. The Commission should begin consideration within one year after enactment of the standard (i.e., by December 19, 2008) and complete its consideration and determination no later than two years after enactment (i.e., by December 19, 2009). Absent such determination, the Commission should consider in a general rate case for each individual electric utility whether or not it is appropriate to implement such standard to carry out the above noted purposes. Should the Commission decline to implement a PURPA standard for which it determines the standard is appropriate to carry out the above-noted purposes, the Commission is directed to state in writing its reasons.[86]

In response to Staff's request, the Commission opened the following dockets in accordance with the mis-numbering of the four new standards as had occurred in the original EISA legislation:

1) Case No. EW-2009-0290: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(16)** Smart Grid Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Smart Grid Investment Docket")

2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(16)** Integrated Resource Planning Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("IRP – Docket")

[84] PURPA Section 101

[85] EISA amended Section 112(c) of PURPA, adding a reference to "paragraphs (16) through (19)" of PURPA Section 111(d). These would be the appropriate numbers had all four of the new PURPA standards been numbered in sequence. EISA also amended PURPA Sections 112(b) and 112(d), referring to "paragraphs (17) through (18)" of PURPA Section 111(d). There is no paragraph (18) or paragraph (19) in EISA to describe the new electric utility standards. (See EISA Section 1307(b).)

[86] PURPA Section 112(c); 16 U.S.C. Section 2622(c).

3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(17)** Rate Design Modifications to Promote Energy Efficiency Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Rate Design Docket")

4) Case No. EW-2009-0293: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(17)** Smart Grid Information Standard as Required by Section 1307 of the Energy Independence and Security Act of 2007. ("Smart Grid Information Docket").

It is my understanding that Congress corrected the mis-numbering of the four new EISA standards in Section 408, Technical Corrections, as enacted as part of the American Recovery and Reinvestment Act of 2009.[87] By May 6, 2009, the Commission issued orders correcting the numbering of the four new PURPA standards and re-numbered and consolidated the workshop dockets as follows:

1) File No. EW-2009-0290: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(16)** Integrated Resource Planning Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("IRP Docket");

2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(17)** Rate Design Modifications to Promote Energy Efficiency Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Rate Design Docket");

3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(18)**, Smart Grid Investments Standard, and PURPA **Section 111(d)(19),** Smart Grid Information Standard as Required by Section 1307 of the Energy Independence and Security Act of 2007. ("Smart Grid Docket").

On November 23, 2009, the Commission issued its *Order Finding Consideration / Implementation Of New Federal Standards Through Workshop And Rulemaking Procedures Is Required* in File Nos. EW-2009-0290, EW-2009-0291, and EW-2009-0292. The Commission stated in its order at page 5, "The Commission has satisfied the requirements for consideration of the new EISA standards, and on the basis of the quasi-legislative record created in these

[87] Pub. L. No. 110-140, 121 Stat. 1492 (2007), amended by Section 408 of The American Recovery and Reinvestment Act of 2009 (the EISA, prior to this amendment, is codified at 16 USCS 2621 and 2622 (Cum. Supp. 2008)). PURPA is codified generally in 16 USCS 2601 et seq., but various provisions appear elsewhere in the United States Code.

workshops, the Commission determines that no comparable standards have been considered that would constitute prior state action and prohibit the Commission from taking any further action in relation to the new EISA standards."

Since there has been no specific determination to date by the Commission, Staff recommends the Commission consider each standard and make its determination with respect to The Empire District Electric Company in this rate case based on the following discussion.

1. IRP Docket

PURPA Section 111(d)(16), Integrated Resource Planning Standard as required by Section 532 of the Energy Independence and Security Act of 2007, requires state commission consideration of whether to implement the following:

> (A) integrate energy efficiency resources into utility, State, and regional plans; and
>
> (B) adopt policies establishing cost-effective energy efficiency as a priority resource.

Staff held several workshops, which culminated in the Commission's promulgation of a rulemaking in File No. EX-2010-0254, In the Matter of a Proposed Rulemaking Regarding Revision of the Commission's Chapter 22 Electric Utility Resource Planning Rules. The revised Chapter 22 rules became effective on June 30, 2011, which require the screening and integration of cost-effective energy efficiency resources to be included in the electric utility resource planning process. After opportunity for input from the public, which included comments being submitted by the electric utilities, Office of the Public Counsel, Missouri Department of Natural Resources, Renew Missouri, Great Rivers Environmental Law Center, and Dogwood Energy, LLC, the Commission approved the policy in Chapter 22 of requiring demand-side resources be evaluated on an equivalent basis with supply-side resources subject to compliance with all legal mandates.[88]

In addition, the Commission has a workshop docket, Case No. EW-2010-0187, opened to investigate how to achieve its statutory responsibilities under the Missouri Energy Efficiency Investment Act ("MEEIA"), Section 393.1075, RSMo., within the background of Federal Energy Regulatory Commission ("FERC") policies that eliminate barriers to demand response and that

[88] 4 CSR 240-22.010(2)(A).

direct the Midwest Independent Transmission System Operator ("MISO") and the Southwest Power Pool ("SPP") to accommodate state policy regarding retail customer demand-side activity. This docket was opened to explore the best model or models to achieve the requirements of the MEEIA through state demand-side programs, wholesale market opportunities available in MISO or SPP, or possible hybrid approaches, and the implications for resource planning under various approaches. The roles for utilities, aggregators of retail consumers ("ARCs"), customers in all classes, and other stakeholders in designing the appropriate means of achieving Missouri's policy objectives, and for interacting with MISO and SPP are also to be evaluated.

While not specifically making a determination to implement PURPA Section 111(d)(16), the Commission has promulgated rulemakings to address the principles of that section; therefore, Staff suggests there is nothing that remains for the Commission to determine in response to PURPA Section 111(d)(16), and recommends the Commission make such a finding in this rate case.

<u>2. Rate Design Docket</u>

PURPA Section 111(d)(17), Rate Design Modifications to Promote Energy Efficiency Investments Standard as required by Section 532 of the Energy Independence and Security Act of 2007, requires state commissions to consider whether to implement: 1) removing the throughput incentive and disincentives to energy efficiency; 2) providing utility incentives for successful management of energy efficiency programs; 3) including the impact of energy efficiency as one of the goals of retail rate design; 4) adopting rate designs that encourage energy efficiency; 5) allowing timely recovery of energy efficiency related costs; and 6) offering energy audits, demand-response programs, publicizing the benefits of home energy efficiency improvements and educating homeowners about Federal and State incentives. Similarly, in 2009, Governor Jeremiah "Jay" Nixon signed Senate Bill 376, the "Missouri Energy Efficiency Investment Act," with a stated policy 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."[89] Section 393.1075.3

The Commission held several workshops, which culminated in the promulgation of a rulemaking in File No. EX-2010-0368, *In the Matter of the Consideration and Implementation of*

[89] Section 393.1075.3, RSMo (Supp. 2010).

Section 393.1075, The Missouri Energy Efficiency Investment Act ("MEEIA"). The rules became effective on May 30, 2011 – Rules 4 CSR 240-20.093, 20.094, 3.163, and 3.164. Empire submitted its MEEIA application on February 28, 2012, in Case No. EO-2012-0206. On June 6, 2012, Empire and certain parties to Empire's 2010 Integrated Resource Planning ("IRP") proceeding (File No. EO-2011-0066), filed a Second Nonunaminous Stipulation and Agreement ("Second Agreement"), which provided for Empire to withdraw its MEEIA application. The Commission approved the Second Agreement and directed Empire to withdraw its MEEIA application no later than seven days after the effective date of the Commission order. On July 5, Empire filed, and the Commission acknowledged, Empire's Notice of Withdrawal. Although Empire withdrew its MEEIA filing, the Commission has in place the framework necessary for the Commission to make a determination on the associated PURPA principles as outlined above.

SB 376 contains a provision which states, "Prior to approving a rate design modification associated with demand-side cost recovery, the commission shall conclude a docket studying the effects thereof and promulgate an appropriate rule."[90] The Commission held additional workshops on this provision of SB 376, and on March 20, 2012, Electric Utility Consultants, Inc. ("EUCI"), provided to the Commission, Staff and interested stakeholders, an in-house, specialized training course on Electric Rate Design Modifications Associated with Demand-Side Cost Recovery.

The revised Chapter 22 rules incorporate requirements for rate design analysis. For instance, 4 CSR 240-22.030(5)(C) requires, at a minimum, that load forecast models assess the impact of legal mandates, economic policies, and rate designs on future energy and demand requirements. Likewise, 4 CSR 240-22.050(4)(B) requires the utility to describe and document its demand-side rate planning and design process, and when appropriate, to consider multiple demand-side rate designs for the major classes.

The Commission sets rates in Missouri based on the cost to serve the customer. This gives the customer accurate cost information on which it can determine whether or not it wants to implement energy efficiency measures. Increasing rates to encourage energy efficiency or setting rates lower for customers that implement energy efficiency sends inaccurate costs signals to the customers. Therefore, without getting into a discussion of general ratemaking principles, but for purposes of the Commission's consideration as to whether it should implement PURPA

[90] Section 393.1075.5, RSMo (Supp. 2010).

Section 111(d)(17), setting rates based on cost to serve the customer sends the appropriate price signal to the customer to make decisions on energy efficiency. The Commission's revised Chapter 22 rules require the electric utilities to look at all forms of incentivizing energy efficiency including home energy audits and demand-response programs.

As a result of these activities, Staff recommends that the Commission, in this case, make a determination that, although additional activities related to SB 376 are contemplated, no further determination is needed in response to PURPA Section 111(d)(17) for Empire.

3. Smart Grid Docket

In response to **PURPA Section 111(d)(18)**, Smart Grid Investments Standard, and **PURPA Section 111(d)(19),** Smart Grid Information Standard, as required by Section 1307 of the Energy Independence and Security Act of 2007, the Commission, on December 29, 2010, issued an order to open File No. EW-2011-0175 as a repository for information concerning the Smart Grid in Missouri.

On January 13, 2011, Staff filed the *Missouri Smart Grid Report* ("Report") in File No. EW-2011-0175. The Report discusses Smart Grid technologies, provides a status update on various Smart Grid opportunities in Missouri and presents issues and concerns related to Smart Grid deployment. It identifies key issues requiring further emphasis, including planning, implementation, cost recovery, cybersecurity and data privacy, customer acceptance and involvement, and customer savings and benefits. The Report recommends the Commission hold a Smart Grid workshop every six months for information exchange and sharing of best practices and educational opportunities; and also recommends the Commission open a docket to address cost recovery issues.

The Commission held Smart Grid conferences on June 28, 2010, and November 29, 2011. Panelist and speaker topics included such items as updates on Smart Grid projects in Missouri, customer views, education and engagement, and challenges to deployment.

The information provided in the workshop is provided to the public through the Commission's electronic filing and information system. The Smart Grid was also the most recent subject of the *PSConnection*, a publication of the Commission which is available online, at public hearings, at the State Fair booth, and at all other opportunities where the Commission interacts with the public.

On July 17, 2012, the Commission issued its *Order Directing Notice and Directing Filing* in File No. EW-2013-0011. The Commission noted, the electric power industry is increasingly incorporating information technology (IT) systems and networks into existing infrastructure, but the increased reliance on IT systems and networks exposes the grid to cybersecurity vulnerabilities. The Commission is charged with assuring public utility companies provide safe and adequate service at just and reasonable rates. The Commission issued its Order to gather information related to cyber vulnerabilities and the integrity of the electric utilities' internal cybersecurity practices. All Missouri regulated electric utilities were required to file answers to all questions contained in the Order by August 31, 2012, and the Commission scheduled an on-the-record proceeding for Monday, November 26, 2012. This file provides yet another opportunity for the Commission to explore issues and take action related to the PURPA standard.

PURPA Section 111(d)(19) requires all electricity purchasers and other interested parties to be provided access to information from their electricity provider related to time-based prices, usage, and sources of power provided by the utility and type of generation, with associated greenhouse gas emissions for each type of generation, to the extent such information is available, on a cost-effective basis. While the Commission has not specifically addressed these issues in the context of PURPA Section 111(d)(19), there have been several forums in which stakeholders have discussed related issues and Staff recommends these issues continue to be addressed as they arise.

Staff recommends the Commission make a determination in this case that it has established the appropriate avenues for monitoring Smart Grid activities and no greater ongoing activity is needed in response to PURPA Section 111(d)(18) and PURPA Section 111(d)(19) in the context of Empire.

Staff Expert/Witness: Natelle Dietrich

B. Smart Grid Update

This section provides information on the history and status of Empire District's Smart Grid deployment and does not address any particular revenue requirements in this rate case. Information for this section was provided by Empire District in response to Data Request No. 0213 and through Empire's presentations in workshops and meetings with the Staff. The

Smart Grid electrical grid infrastructure components currently in operation or planned for the future (Smart Meters and Outage Management System upgrades) include the following.

- **Smart Meters.** Currently only electro-mechanical meters are deployed. Smart meter deployment was attempted earlier but abandoned due to failures in the communication infrastructure deployment. In March 2010, Empire District Electric assembled a team to develop a pilot program that would research and test the available metering products and technologies for an advanced metering infrastructure system. The team determined it would need to visit with a number of manufacturers, vendors, and other utility companies. The team determined it was also necessary to identify the required interfaces and to define the corporate resources needed to ensure a successful future pilot project implementation.
- **Transformer Insulating Oil Dissolved Gas Monitors**. This equipment provides real time monitoring of the moisture and combustible gases that are dissolved in the insulating oil of three transmission (over 100 KV) autotransformers[91]. The detection of certain combustible gases and moisture provides an early warning system of an impending transformer internal fault that will destroy the transformer and cause significant collateral damage.
- **Smart line capacitors.** Capacitor banks control or stabilize the system voltage by minimizing voltage drops and absorbing energy from a line spike. The banks provide voltage stability by switching in capacitor banks to provide reactive power when large inductive loads occur, such as when air conditioners, furnaces, dryers, and/or industrial equipment start. These capacitors are automatically controlled by a microprocessor based program that actuates based upon time, temperature, voltage and reactive power inputs.
- **Smart Line Switches.** These devices are installed in Branson, MO, and detect line disturbances and provide communication of events to system operations personnel, isolate faulted lines, and restore service via alternate paths.
- **Faulted Circuit Indicators.** These devices provide information on line disturbances and communicate this information to system operators in near real

[91] An autotransformer utilizes one set of windings with multiple connection points to change voltage levels.

time for faster identification of problems and locating faulted circuits. These devices are currently installed where the three-phase supply service splits to serve two different loads.

- **Automatic Voltage Regulation and Control.** Automatic voltage regulation is installed at the majority of all distribution substations and consists of Voltage Regulators and/or Transformer load tap changers.
- **Automatic Supply Line Transfer.** These systems are installed in Branson, MO to detect supply line disturbances and automatically reconfigure distribution substation switching to restore power following an outage.
- **Microprocessor Relaying.** For the past fifteen years, Empire has been changing from electro-mechanical to digital relaying that provides improved operating performance and self-diagnostic checks.
- **Supervisory Control and Data Acquisition (SCADA).** These systems are deployed in the switchyards and provide real time outage notification for enhanced outage response performance, improve operating flexibility and prevent overloads. Open Systems International (OSI)[92] Energy Management System (EMS) system upgrades were completed in September of this year.
- **Outage Management System (OMS).** This Intergraph InService Outage Management System[93] provides outage management services that includes collecting customer call data and creates and prioritizes work orders to optimize the Company's response to outages by shortening the outage duration and improving efficiency. System upgrades, including the interface with the SCADA system are scheduled for completion by the end of this year.
- **Wide Area Networks (WAN).** A WAN is a high capacity communications backbone network that transports large quantities of data to the Company's data centers, most service centers and customer service offices. Empire owns and operates its own fiber optic WAN.

[92] http://www.osii.com/index.asp?nsgc

[93] http://www.intergraph.com/utilities/oms.aspx

- **Field Area Network (FAN).** A FAN is a wireless communication network. The OMS system utilizes a cellular wireless network for communication with Empire's service trucks.
- **Local Area Network (LAN).** This network aggregates data and interfaces with the WAN to provide internal company communications.

Staff Expert/Witness: Randy S. Gross

C. Light Emitting Diode (LED) Street and Area Lighting

In the Company's last rate case, Case No. ER-2011-0004, the Commission's June 1, 2011 *Order Approving Global Agreement* ordered the following related to the Company's LED lighting tariff in Paragraph 10:

> "… Within one year of effective dates of rates in this case, Empire agrees to file either LED lighting tariff sheets or an update on an LED pilot study and plans for filing future tariff sheets."

Empire personnel met personally with Staff in Jefferson City on July 14, 2011, and August 25, 2011, to discuss the Company's efforts pertaining to the *Order Approving Global Agreement*. During these meetings, Staff recommended that Empire interact with KCPL due to KCPL's LED lighting pilot program with Westar Energy funded by a Mid-America Regional Council LED grant.[94] However, Empire has not filed either LED lighting tariff sheets or an update on a LED pilot study and plans for filing future tariff sheets within one year of the June 15, 2011 effective date of rates in the Company's last rate case.

Empire has not complied with the Commission's *Order Approving Global Agreement*. Staff recommends that the Commission's *Report and Order* in this case order Empire to complete its own evaluation of LED SAL systems and file either a proposed LED lighting tariff sheet(s), or an update to the Commission on when it will file a proposed LED lighting tariff sheet(s) with or without completion of its own independent pilot program of LED SAL systems,[95] no later than twelve (12) months following the Commission's *Report and Order*. Staff is not recommending that Empire offer the LED SAL program as a demand-side program

[94] Case No. ER-2012-0174, Staff Cost of Service Report, pp. 228 – 229.

[95] Currently, there is some accessible information from other municipalities or utilities. Also, one can access information from various Department of Energy (DOE) websites at http://www1.eere.energy.gov/buildings/ssl/resources html

unless Empire's analysis shows that a LED SAL demand-side program would be cost-effective. However, if a LED SAL demand-side program is not cost-effective, the Staff recommends that Empire update the Staff as to the finding's rationale and file a proposed tariff sheet(s) within the same twelve (12) month time frame recommended above that would provide LED SAL demand-side program services at cost to its customers.

Staff Expert/Witness: Hojong Kang

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

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

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 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company)	Case No. ER-2012-0345

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

Subscribed and sworn to before me this 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

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

Alan J. Bax

Alan J. Bax

Subscribed and sworn to before me this 29th day of November, 2012.

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Daniel I. Beck, 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.

Daniel I Beck

Daniel I Beck

Subscribed and sworn to before me this 29th day of November, 2012.

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF KIMBERLY K. BOLIN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kimberly K. Bolin, 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.

Kimberly K. Bolin

Kimberly K. Bolin

Subscribed and sworn to before me this 29th day of November, 2012.

D. SUZIE MANKIN
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D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF NATELLE DIETRICH

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Natelle Dietrich, 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.

Natelle Dietrich

Natelle Dietrich

Subscribed and sworn to before me this 29th day of November, 2012.

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

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF DAVID W. ELLIOTT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

David W. Elliott

Subscribed and sworn to before me this 29th day of November, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
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In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

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

Subscribed and sworn to before me this 29th day of November, 2012.

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

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF JERMAINE GREEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Jermaine Green, 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.

J Green

Jermaine Green

Subscribed and sworn to before me this 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Randy S. Gross

Subscribed and sworn to before me this 29th day of November, 2012.

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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OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

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

Subscribed and sworn to before me this 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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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

Subscribed and sworn to before me this 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Robin Kliethermes, 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.

Robin Kliethermes

Robin Kliethermes

Subscribed and sworn to before me this 29th day of November, 2012.

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 SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Shawn E Lange

Shawn E. Lange

Subscribed and sworn to before me this 29th day of November, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2012-0345

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

Subscribed and sworn to before me this 29th day of November, 2012.

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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

Subscribed and sworn to before me this 29th day of November, 2012.

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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

Subscribed and sworn to before me this 29th day of November, 2012.

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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

Subscribed and sworn to before me this 29th day of November, 2012.

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D Suzie Mankin

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AFFIDAVIT OF CASEY WOLFE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Casey Wolfe, 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 Wolfe

Casey Wolfe

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AFFIDAVIT OF SEOUNG JOUN WON, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, 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.

Seoung Joun Won
Seoung Joun Won, PhD

Subscribed and sworn to before me this 29th day of November, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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D Suzie Mankin
Notary Public