MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT

COST OF SERVICE

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

CASE NO. ER-2012-0166

Jefferson City, Missouri
July 6, 2012

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

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I. Executive Summary

The Staff has conducted a review in Case No. ER-2012-0166 of all revenue requirement cost of service components (capital structure and return on rate base, rate base, depreciation expense and other operating expenses) which comprise Union Electric Company's d/b/a Ameren Missouri ("Ameren Missouri" or "Company") revenue requirement. This audit was in response to Ameren Missouri's filing made on February 3, 2012, seeking to increase its retail rates to recover an additional approximately $375.6 million on an annual basis.

The Staff's recommended increase in revenue requirement is based upon an adjusted test year for the twelve months ending September 30, 2011, including true-up estimates through July 31, 2012. The Staff's recommended revenue requirement for Ameren Missouri is $152,480,937 to $210,300,136 based on a return on equity (ROE) range of 8.00% to 9.00%.

The impact of the Staff's recommended revenue requirement for each retail rate customer class will be addressed in the Staff's rate design direct testimony and report that is to be filed on July 19, 2012.

Staff Expert/Witness: John P. Cassidy

II. Background of Ameren Missouri

Ameren Missouri provides electric utility service to approximately 1.2 million retail customers primarily in the eastern half of Missouri, but also to a limited extent in northwestern Missouri. Ameren Missouri is wholly owned by Ameren Corporation (Ameren), which also provides utility service in Illinois through its Ameren Illinois operating subsidiary. Ameren Missouri also operates a natural gas distribution business in Missouri, which serves approximately 127,000 customers.

Ameren Missouri last sought a general change of its electric retail rates when it filed for a $263 million annual increase on September 3, 2010, in Case No. ER-2011-0028. As a result of the Missouri Public Service Commission's ("PSC" or "Commission") Report and Order in that proceeding, Ameren Missouri was granted a general annual rate increase of approximately $173.2 million, effective July 31, 2011.

Staff Expert/Witness: John P. Cassidy

III. Test Year/True-Up Period

Ameren Missouri filed its case based upon a twelve-month-ending September 30, 2011, test year and made adjustments to its case to reflect the impacts of anticipated changes through July 31, 2012, its requested true-up period end date. These dates were ordered by the Commission on March 28, 2012, in its Order Adopting Procedural Schedule, Establishing Test Year, And Delegating Authority.

The Staff's revenue requirement as presented in its Accounting Schedules includes expected changes for a true-up ending July 31, 2012, based on current information. For example, the plant and depreciation reserve balances have been adjusted to reflect the anticipated additions through the July 31, 2012, true-up period. Fuel expense has also been adjusted, based on the January 2012 coal contract prices. The Staff expects to consider changes to these items, as well as additional components of the cost of service, during the true-up audit. The Staff is not now adopting for the purpose of setting Ameren Missouri's rates the items listed and quantified in the Staff's true-up estimate. The Staff has included these items as placeholders, pending the Staff's completion of its true-up audit.

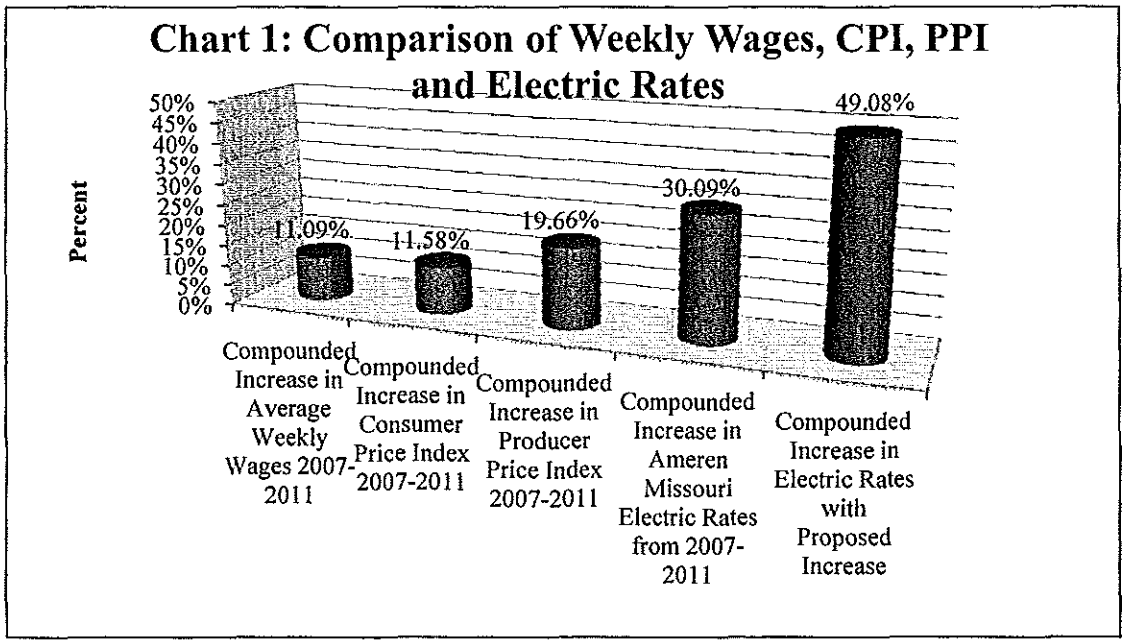
Staff Expert/Witness: John P. Cassidy

IV. Economic Considerations

As demonstrated below, Missouri, and specifically the counties[1] of the service area of the Ameren Missouri, have experienced challenging economic times since 2007 due to the recession and a slow recovery. Additionally, Ameren Missouri customers have experienced a 30.09% increase in electric rates, while experiencing an increase in income of less than one-half of that amount since 2007. Chart 1 provides a comparison of the increase in average weekly wages for

[1] According to Schedule 2 of the minimum filing requirements and the current tariffs, Ameren Missouri serves a total of 60 counties and the independent City of St. Louis. The Quarterly Census of Employment and Wages designates the independent City of St. Louis as a county, making the Ameren Missouri service area a total of 61 counties.

the counties in the Ameren Missouri service area, Consumer Price Index ("CPI"), Producer Price Index ("PPI")[2] and Ameren Missouri electric rates.



From 2007 to 2011,[3] the counties in the Ameren Missouri service area collectively experienced an 11.09% increase in average weekly wages. This was slightly lower than the overall Missouri compounded increase in average weekly wages of 11.63%. During that same time period, the CPI increased 11.58% and electric rates for customers served by Ameren Missouri increased 30.09% in Case Nos. ER-2007-0002, ER-2008-0318, ER-2010-0036, and ER-2011-0028, which accumulated to a total increase of approximately $607 million, shown in Table 1. However, Ameren Missouri has also experienced inflationary pressure illustrated by a 19.66% increase in the PPI for Industrial Commodities from 2007 to 2011.[4] Ameren Missouri is currently requesting an additional $376 million or a 14.6% increase in rates.

[2] The PPI represents the Producer Price Index for Industrial Commodities which 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.

[3] Data for 2011 is still preliminary.

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

Table 1: Ameren Missouri Rate Case History 2007 - 2011

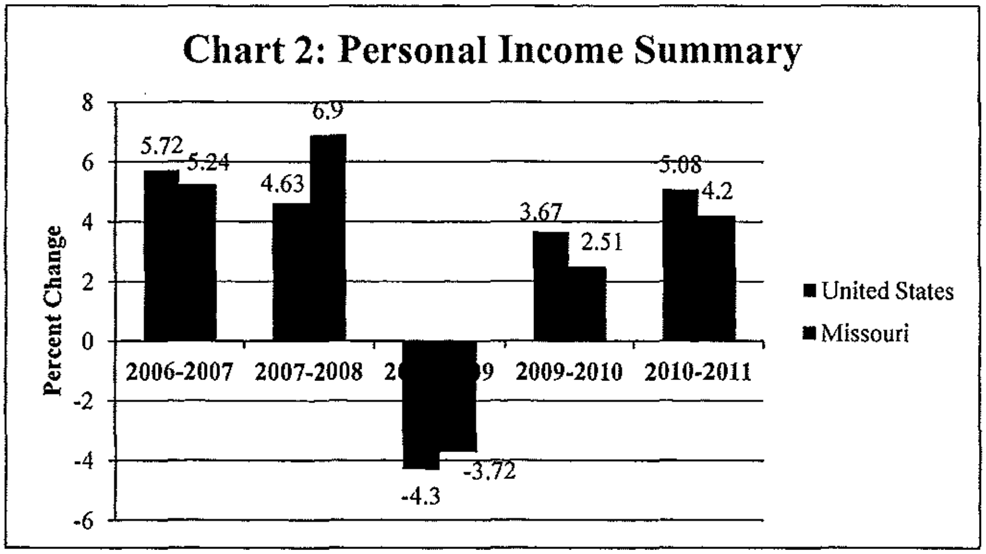
Case Number	Effective Date	Dollar Value	Percent Increase
ER-2007-0002	June 1, 2007	$41,777,474	2.07%
	July 23, 2007	$1,010,430	
ER-2008-0318	March 1, 2009	$161,709,205	7.75%
ER-2010-0036	June 21, 2010	$229,552,309	10.43%
ER-2011-0028	July 31, 2011	$173,225,030	7.11%
Total Dollars		$607,274,448	
Total Compounded Increase			30.09%

The increase in average weekly wages for counties in the Ameren Missouri service area is less than one-half of the increase in electric rates for Ameren Missouri customers from 2007 to 2011 and approximately one-quarter of the increase in rates if Ameren Missouri received its requested 14.6% increase. Furthermore, in the first quarter of 2012, the cost of living utility index[5] for Missouri was 103.1. This indicates that general utility expenses constitute a higher percentage of a 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 which serves as the comparison at 100. Although average weekly wages are increasing, the cost of living as reflected by the CPI is also increasing, decreasing the positive impact of the increase in average weekly wages.

Based on the direct testimony of Company witness John J. Reed and information from the Federal Reserve Bank of St. Louis, Missouri's economic recovery has been weaker compared to the nation as a whole. Chart 2 illustrates this through a comparison of personal income between the United States as a whole and Missouri, based on data obtained from the Bureau of Economic Analysis. The data shows that Missouri had a percentage change of positive 4.2% in

[5] Source: Missouri Economic Research and Information Center (MERIC) and The Council for Community & Economic Research – 1st Quarter 2012. The cost of living composite index represents indices for grocery items, housing, utilities, transportation, health care and miscellaneous services. The utility index includes electric, natural gas and telephone services.

personal income, while the nation experienced a percentage change of positive 5.08% between 2010 and 2011.



In addition, Company witness Reed also reported on Missouri's coincident index, or economic performance.[6] According to the Current Economic Conditions in the Eighth Federal Reserve District report from the Federal Reserve Bank of St. Louis, as of March 2012, Missouri's coincident index is at 89.7% of its pre-recession level compared to the nation's coincident index at 97% of its pre-recession level. Missouri also fell behind the nation in Gross Domestic Product ("GDP")[7] growth in 2010 and 2011[8] as illustrated in Chart 3.

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[6] Based on information from the Federal Reserve Bank of St. Louis using the Federal Reserve Bank of Philadelphia's coincident index, which is a combination of payroll employment wages, unemployment and hours of work to give a single measure of economic performance

[7] Staff Expert/Witness David Murray discusses Gross Domestic Product ("GDP") and the utility industry in detail later in the Staff Cost-of-Service Report.

[8] Advance 2011 real GDP by state statistics and revised 1997-2010 statistics were released on June 5th, 2012, by the Bureau of Economic Analysis. Real GDP by Metropolitan Statistical Area ("MSA") for 2011 have not yet been released.

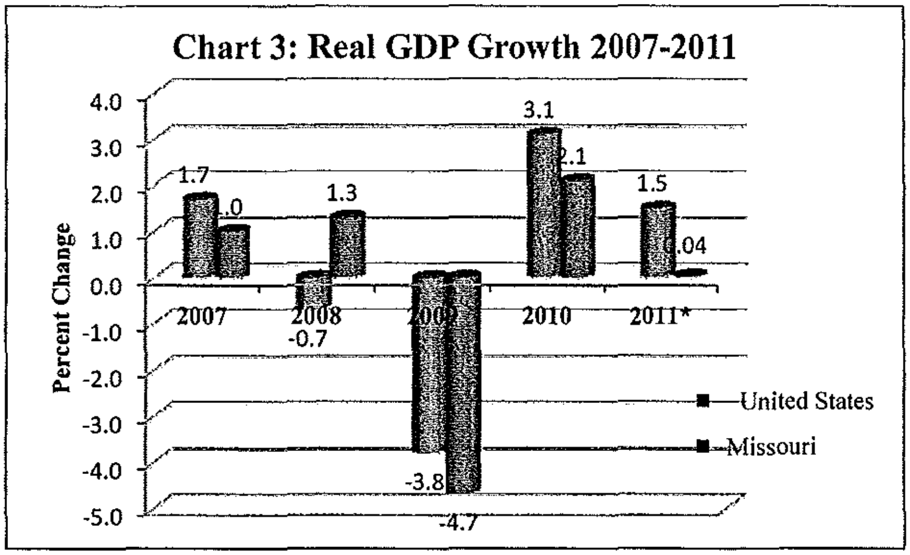

Chart 3 shows that Missouri's real GDP[9] only increased 0.04% in 2011, while the nation's real GDP grew 1.5% in 2011. In 2010, Missouri's real GDP grew less than the nation's real GDP at 2.1% and 3.1%, respectfully. Growth in real GDP occurred in 2010 after Missouri's real GDP declined by 4.7% in 2009, compared to the nation's real GDP decline of 3.8%. In "Facts About Ameren Missouri," posted on the Ameren Missouri website, it is reported that 53% of its electric customers are located in the St. Louis metropolitan area. The St. Louis MO-IL Metropolitan Statistical Area ("MSA"),[10] which includes 8 counties in Illinois and 8 counties[11] in Missouri, reported an increase in real GDP of 1.5% in 2010 which also fell behind the U.S. metropolitan portion's increase in real GDP of 2.5%. The St. Louis MO-IL MSA also experienced a decline in real GDP of 4.2% in 2009, which was greater than the U.S metropolitan portion's decline of 2.5%. The personal income data, the coincident index data and the real GDP data support Mr. Reed's conclusion that Missouri is experiencing a slower recovery than the nation.

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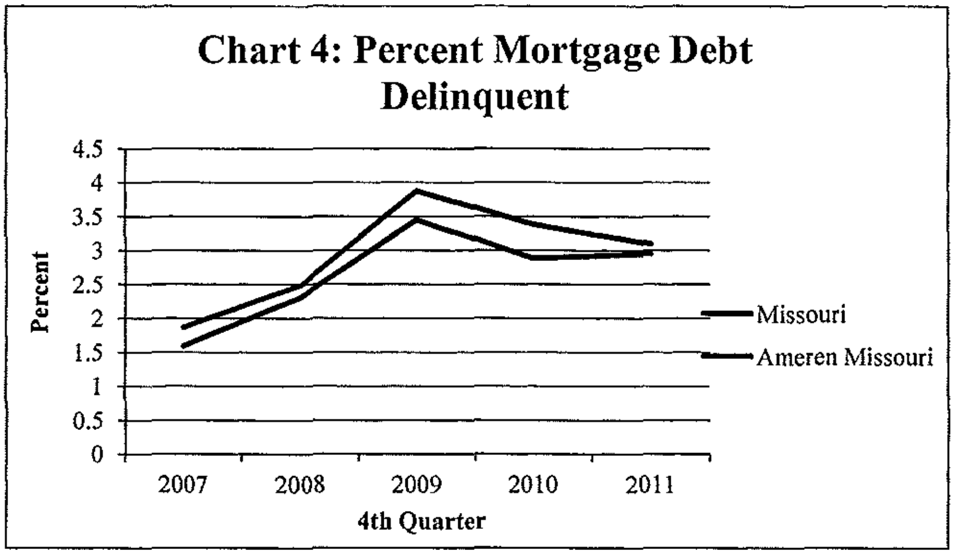
[9] Source: Bureau of Economic Analysis – Real GDP by State, All Industries.

[10] The Bureau of Economic Analysis reports that GDP by state is "the value added in production by the labor and capital located in a state" and GDP by metropolitan area is "the measure of the market value of all final goods and services produced within a metropolitan area in a particular period of time."

[11] All eight Missouri counties (Franklin, Jefferson, Warren, Washington, Lincoln, St. Charles, St. Louis, and St. Louis City) are located in the Ameren Missouri service area.

As explained below, the counties in the Ameren Missouri service area are collectively trying to recover from a recession where the unemployment rate peaked at 9.5%[12] in 2009, on lower than the national average weekly wages and lower than the national average per capita personal income. However, the counties in the Ameren Missouri service area do have, on average, a lower percentage of mortgage debt than the state average, as shown in Chart 4. Nevertheless, percent mortgage debt delinquency has increased greatly between the fourth quarter of 2007 and the fourth quarter of 2011 for both the Ameren Missouri service area and the state in general. The values in Chart 4, shown below, can be interpreted as the percent of mortgage debt balance that is 90+ days delinquent.[13]



Of the counties[14] in the Ameren Missouri service area, Madison County had the highest percent of mortgage debt balance 90+ days delinquent in 2011 at 8.69%, up from 1.22% in 2007; St. Louis City followed at 5.08% in 2011, up from 3.75% in 2007. Linn County reported the lowest mortgage debt delinquency rate at 0.21%. Of the three largest cities in Missouri

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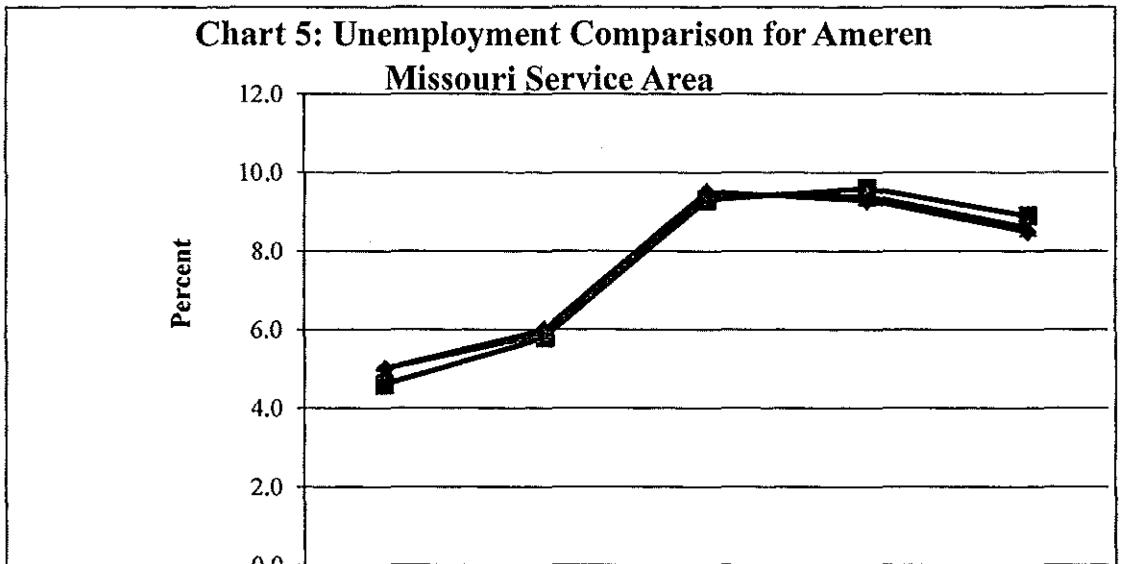
[12] The Ameren Missouri service area unemployment rate is calculated as a percentage of total labor force.

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

[14] 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 37 of the 61 counties in the Ameren Missouri service area.

(Kansas City, St. Louis and Springfield), St. Louis reported the highest percentage of mortgage delinquency at 5.08% in 2011.[15]

Counties in the Ameren Missouri service area had a slightly higher unemployment rate[16] than Missouri and the U.S. in 2008 and 2009, but fell slightly below Missouri and the U.S. unemployment rates in 2010 and 2011 as demonstrated in Chart 5, below. Although the unemployment rate seems to be decreasing in 2011, all of the counties in the Ameren Missouri service area have higher rates in 2011 than pre-recession or 2007 unemployment levels.



	2007	2008	2009	2010	2011
Ameren Missouri	5.0	6.0	9.5	9.3	8.5
United States	4.6	5.8	9.3	9.6	8.9
Missouri	5.0	5.9	9.4	9.4	8.6

[15] Source: Consumer Credit Report – Missouri, Federal Reserve Bank of Kansas City – Tenth District, 4th Quarter 2011.

[16] Source: Bureau of Labor Statistics, Local Area Unemployment Statistics. The unemployment rate is calculated as a percentage of the labor force.

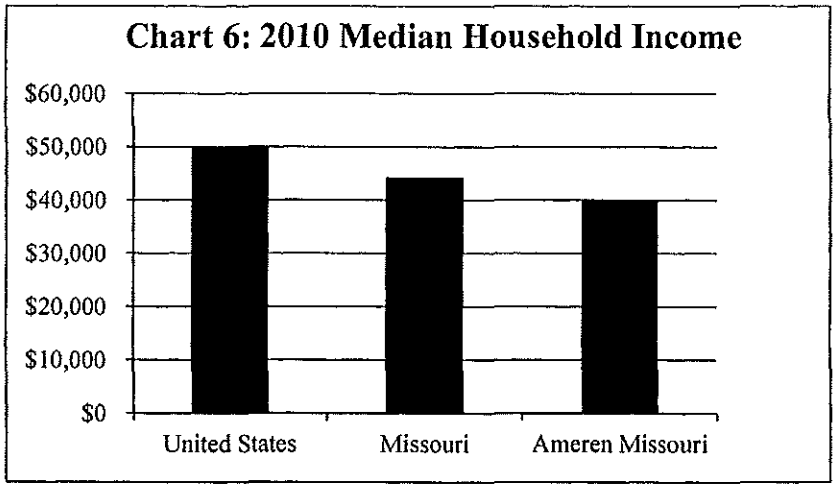
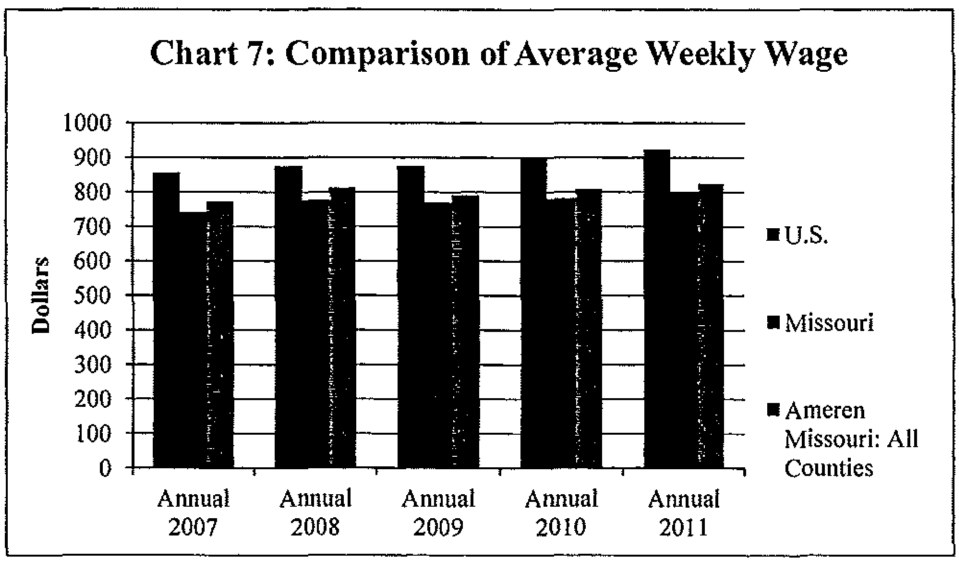
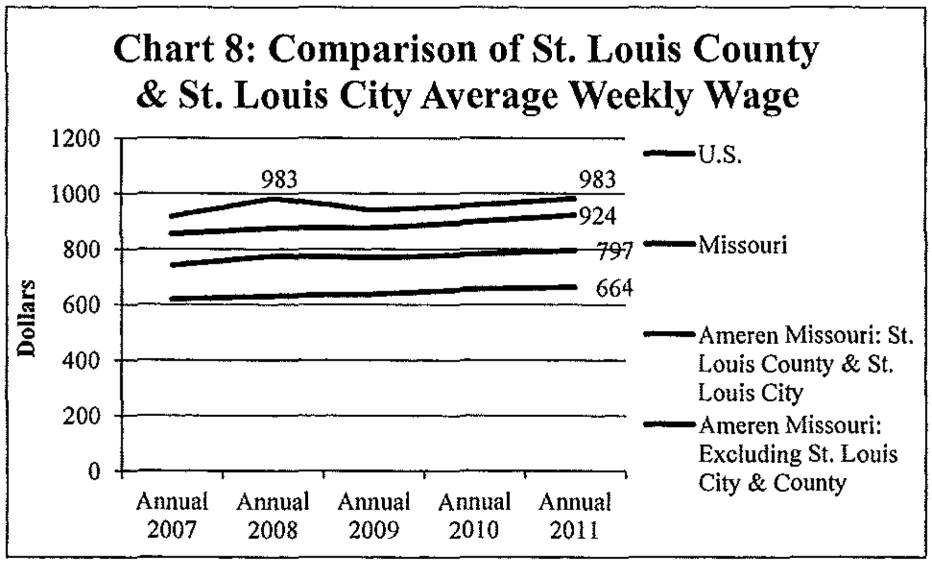


Chart 6 illustrates median household income based on data from the Missouri Economic Research and Information Center ("MERIC"). On average, counties in the Ameren Missouri service area fell below the national and state 2010 median household income levels. The average weekly wage[17] for the Ameren Missouri service area is also below the national average, but slightly higher than the state average shown in Chart 7.



[17] 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."

In 2011, the national average weekly wage was reported at $924. The only two counties served by Ameren Missouri that reported average weekly wages higher than the national average were St. Louis City at 10.3% higher at $1,019 and St. Louis County followed at 4.9% higher than the national average at $969. At $1,019, St. Louis City reported the highest average weekly wage amongst the counties; however, it has not reported an average weekly wage that high since 2008 at $1,010. Since St. Louis County and St. Louis City have a higher average weekly wage than the rest of the 59 counties, Chart 8 illustrates a comparison of the average weekly wage for only St. Louis City and St. Louis County, as compared to the average weekly wage for the other 59 counties served by Ameren Missouri.



In Chart 8, the average weekly wage for St. Louis City and St. Louis County, although higher than the average weekly wage for the rest of the 59 counties served by Ameren Missouri, is just recovering back up to the 2008 average weekly wage value in 2011.[18]

Again, 53% percent of Ameren Missouri's customers are in the St. Louis metropolitan area[19] and experience a higher than average weekly wage; however, 47% experience a lower weekly wage than the national and state average weekly wages. The median average weekly

[18] The 2011 average weekly wage values are still preliminary.

[19] Based on customers per county reported in Ameren Missouri's outage report on the Ameren Missouri website the statement in the "Facts About Ameren Missouri" that "53% of its customers reside in the St. Louis metropolitan area" can only include its customers in St. Louis County and St. Louis City.

wage in 2011, including all 61 counties, is $553, meaning 50% of the counties are below this value and 50% are above. Another income variable is per capita personal income.[20] In 2010,[21] four counties (St. Louis County - $51,512, St. Charles - $39,441, Clay - $36,830 and Cole - $39,755) reported per capita personal income levels above the state level of $36,799.[22] However, just as with state per capita personal income, none of the four counties had per capita personal income levels in 2010 that were higher than per capita personal income levels in 2008. In 2009, the Ameren Missouri service area experienced a decrease of 4.82% in personal income, which was more than the decrease experienced by the state (3.72%) and the nation (4.3%).[23] In 2011, Missouri reported per capita personal income at $38,248, which fell below the national per capita personal income level of $41,663. However, this was the first time both the state and the nation experienced a per capita personal income level that surpassed 2008 levels by approximately 1.5%.

Even though Ameren Missouri's rates are lower than the national average, 47% of Ameren Missouri's customers receive a weekly wage below the national average weekly wage; over half of its customers enjoy less personal income than the national average per capita personal income and unemployment rates are above 2007 pre-recession unemployment rates for all 61 counties where Ameren Missouri provides service.

Staff Expert/Witness: Robin Kliethermes

V. Major Issues

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

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[20] The Bureau of Economic Analysis calculates per capita personal income as total personal income divided by the Census Bureau's annual midyear population estimates.

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

[22] Only St. Louis County had a level above the national level ($39,937).

[23] Shown in Chart 3.

Return on Equity (ROE) – Issue Value – ($101 million difference based on applying difference in ROEs to the rate base presented by Ameren Missouri). The Staff supports the high end of its ROE recommendation of 9.00%. Ameren Missouri is requesting a 10.75% ROE. This issue is addressed in detail in Section VI of this report by Staff witness David Murray.

Property Tax Expense – Issue Value – ($12.7 million difference). Ameren Missouri is seeking an increase in ongoing property taxes based on estimated growth in investment and also for investment associated with their new methane powered energy center. Staff annualized property taxes based on actual 2011 property tax bills.

Entergy Refund – Issue Value – ($10.2 million difference). This difference relates to the refund that Ameren Missouri received from Entergy during June 2012 based upon a recent Federal Energy Regulatory Commission (FERC) Order. Since this refund occurred subsequent to the Company's direct filing, this refund is not addressed by the Company's cost of service calculation. The Staff recommends that this refund be refunded to customers over a three year period beginning with the effective date of rates in this rate proceeding.

Revenues – Issue Value - ($9.0 million difference). The overall difference in revenue calculation that exists between Company and Staff is $9.0 million. The primary difference that exists with regard to revenues has to do with the difference in the weather history data that was used by the Company and Staff with regard to the ultimate determination of weather normalization of usage.

Severance – Issue Value – ($8.6 million difference). This difference relates to the recovery of severance costs associated with a Voluntary Separation Program offered to employees subsequent to the test year. Ameren Missouri is seeking a three year recovery for these costs. Staff contends that Ameren Missouri will achieve cost savings to offset these severance costs and that no adjustment to the cost of service is necessary to address these costs.

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

Staff Expert/Witness: John P. Cassidy

VI. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return ("ROR"), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis. Staff's expert financial analyst, David Murray, has determined Ameren Missouri's cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, net of any risk adjustments, together with other capital component information as of September 30, 2011, to calculate Ameren Missouri's fair rate of return, as follows:

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	8.00%	8.50%	9.00%
Common Stock Equity	53.02%	-----	4.24%	4.51%	4.77%
Preferred Stock	1.04%	4.18%	0.04%	0.04%	0.04%
Long-Term Debt	45.94%	5.885%	2.70%	2.70%	2.70%
Total	100.00%		6.99%	7.25%	7.52%

As contained in the above table, Staff estimates, based upon its expert analysis, a cost of common equity range of 8.00% to 9.00%, mid-point 8.50%, and an overall ROR of 6.99% to 7.52%, mid-point 7.25%. Staff recommends that the Commission authorize a return on common equity of 9.00% based on the high-end of its estimated cost of equity 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 1-23. 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 Ameren Missouri are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the government must allow a reasonable opportunity for the shareholders to earn a fair return on their investment. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases.[24] In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:[25]

> 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:[26]

> '[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

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[24] *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).

[25] 262 U.S. 679, 692-693, 43 S.Ct. 675, 679, 67 L.Ed. 1176.

[26] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345.

> 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.

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

The methodologies of financial analysis have advanced greatly since the *Bluefield* and *Hope* decisions.[27] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return Ameren Missouri's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific Discounted Cash Flow ("DCF") method satisfies the constitutional principles inherent in estimating a return consistent with those of

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

companies of comparable risk;[28] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for Ameren Missouri.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***. However, as Staff will discuss extensively throughout this section of the report, Staff believes its recommended return on equity is higher than Ameren Missouri's cost of equity.

C. Current Economic and Capital Market Conditions

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

1. Economic Conditions

The United States 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,

[28] 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*.

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 economic 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%.[29] These projected long-term nominal GDP growth rates generally are predicated on 2% expected inflation, as measured by the GDP price deflator.

The Federal Reserve Bank ("the Fed") continues to maintain the Fed Funds Rate at historically low levels between 0.00% and 0.25% (*see* Schedules 2-1 and 2-2). Additionally, the Fed decided in meetings held on June 19 and 20, 2012, to extend its bond buy-back program, "Operation Twist," through the end of the year. Through this program, the Fed hopes to continue to maintain, if not further reduce, already low long-term interest rates. Fed Chairman Ben Bernanke bluntly indicated, "if we don't see continued improvement in the labor market we'll be prepared to take additional steps." The Fed's announcement was accompanied by a revised outlook for lower economic growth in the near term as compared to previous estimates. The Fed now projects the economy will grow between 1.9% and 2.4% this year and less than 3% next year. The Fed also lowered its estimates for inflation to 1.2% to 1.7% for this year from its previous projection of 1.9% to 2.0% in April. The Fed continues to communicate to the markets that it will keep short-term interest rates low until late 2014.[30]

Consequently, while there is much debate regarding the effect current monetary policy may have on inflation, it appears that the Fed's primary concern is still the lack of sustainable growth in the economy. 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

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[29] The Congressional Budget Office ("CBO"), *The Budget and Economic Outlook: Fiscal Years 2012-2022*, January 2012; Minutes from the Federal Open Market Committee's ("FOMC") meeting on April 24-25, 2010; First Quarter 2012 Survey of Professional Forecasters; Energy Information Administration's 2012 Annual Energy Outlook and The Livingston Survey, June 7, 2012.

[30] Kristina Peterson and Jon Hilsenrath, "Fed Warns of Risk to Economy, Central Bank Extends Bid to Lower Long-Term Rates, Stands Poised to Do More," *Wall Street Journal*, June 21, 2012, p. A1 and A14.

Inflation Protected Securities ("TIPS") and non-inflation protected Treasury bonds implies investors are requiring an additional 2.25% to 2.40% return for potential inflation.[31]

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 3% range. For example, The Empire District Electric Company 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[32] required to invest in utility stocks rather than utility bonds was constant, then these lower utility debt yields directly translate into a lower required return on equity. In other words, a lower cost of debt is indicative of a lower cost of capital, all else being equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are typically 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 May 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 (1.91%), 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.)

Not only has the cost of investment-grade debt capital declined considerably, but it appears that the cost of non-investment grade debt has declined, as well (*see* Schedule 4-6). However, the spread between investment-grade and non-investment grade debt is higher than it was during the loose credit years during the middle of the previous decade (*see* Schedule 4-7).

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

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

b. Utility Equity Markets

For the twelve months ending December 31, 2011, the total return on the Dow Jones Industrial Average was 8.38%, the total return on the Standard & Poor's 500 ("S&P 500") was 2.11%, and the total return on the Edison Electric Institute ("EEI") Index of electric utilities was 19.99%. More specifically, on a non-market capitalization weighted basis, the total return for the twelve months ending December 31, 2011, was 22.30% for EEI "Regulated" electric utilities, 19.52% for EEI "Mostly Regulated" electric utilities and 21.36% for "Diversified" electric utilities.

Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely to be more affected by general economic trends. Although the returns of EEI's "Diversified" electric utilities and "Mostly Regulated" electric utilities had lagged that of "Regulated" Utilities in 2010, in 2011 the returns of all the categories were quite strong as compared to the broader markets. "Regulated" utilities' total returns in 2010 were 15.75%. Adding the "Regulated" utilities' returns for 2011 with those achieved in 2010, totals 38.05% over the last two years, a truly spectacular couple of years for electric utility stock returns. 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 Ameren Missouri rate case. The average forward price-to-earnings ("p/e") ratio for these eight companies increased from 13.19x to 14.67x in just a little over a year. There are two primary drivers for higher p/e ratios, higher expected growth in earnings and/or a lower cost of equity, i.e. investors willing to pay a higher price per unit of earnings. In this case, it appears to be the latter because the projected 5-year earnings-per-share ("EPS") forecasted growth rates have actually declined since the last rate case. This is a clear indication that the cost of equity has declined since the last Ameren Missouri 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. 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. Clearly, this means that investors are not paying a higher p/e for electric utility stocks for growth, but because of the low comparative returns offered by bonds. 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 returns on common equity ("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.[33]

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.

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[33] 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

D. Ameren's and Ameren Missouri's Operations

1. Ameren

The following excerpt from Ameren's Form 10-Q filing with the United States Securities Exchange Commission ("SEC") for the quarter ended March 31, 2012, provides a good description of Ameren's current business operations and current organizational structure:

> Ameren, headquartered in St. Louis, Missouri, is a public utility holding company under PUHCA 2005, administered by FERC. Ameren's primary assets are the common stock of its subsidiaries. Ameren's subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. These subsidiaries operate, as the case may be, rate-regulated electric generation, transmission and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant electric generation businesses in Missouri and Illinois. Dividends on Ameren's common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Ameren's principal subsidiaries are listed below. Also see the Glossary of Terms and Abbreviations at the front of this report and in the Form 10-K.
>
> • Union Electric Company, or Ameren Missouri, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business, in Missouri.
>
> • Ameren Illinois Company, or Ameren Illinois, operates a rate-regulated electric and natural gas transmission and distribution business in Illinois.
>
> • AER consists of non-rate-regulated operations, including Genco, AERG, and Marketing Company. Genco operates a merchant electric generation business in Illinois and holds an 80% ownership interest in EEI, which it consolidates for financial reporting purposes.
>
> Ameren has various other subsidiaries responsible for activities such as the provision of shared services.

2. Ameren Missouri

In Note 1 to Ameren's Combined Notes to Financial Statements, December 31, 2011, Ameren provides the following description of Ameren Missouri's operations:

> Union Electric Company, or Ameren Missouri, operates a rate-regulated electric generation, transmission and distribution business, and a rate-regulated natural gas transmission and distribution business in Missouri. Ameren Missouri was incorporated in Missouri in 1922 and is successor to a number of companies, the oldest of which was organized in 1881. It is the largest electric utility in the state of Missouri. It supplies electric and

> natural gas service to a 24,000-square-mile area in central and eastern Missouri. This area has an estimated population of 2.9 million and includes the Greater St. Louis area. Ameren Missouri supplies electric service to 1.2 million customers and natural gas service to 127,000 customers.

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

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

Ameren Missouri's Moody's, S&P and Fitch issuer/corporate credit rating are 'Baa2', 'BBB-', and 'BBB+', respectively. Ameren's Moody's, S&P and Fitch issuer/corporate credit rating are 'Baa3', 'BBB-', and 'BBB', respectively.[34] Moody's and Fitch rate Ameren one notch lower than Ameren Missouri because Moody's and Fitch tend to give more weight to the stand-alone financial risk and business risk of the subsidiary, i.e. they view Ameren Missouri's credit quality as being stronger than that of the parent. However, S&P's ratings methodology is based on its view that without significant ring-fencing mechanisms in place, they will rate the subsidiary based on the consolidated credit quality of the parent company. In fact, S&P does not even provide Ameren Missouri's stand-alone financial ratios in its published research reports. S&P only publishes Ameren's financial ratios.

The following is an excerpt from a March 16, 2012, S&P credit-rating report on Ameren Missouri:

> Standard & Poor's Ratings Services' ratings on St. Louis-based Ameren Missouri (AM) reflect the consolidated credit profile of its parent, Ameren Corp. (Ameren). The ratings also reflect AM's "excellent" business risk profile and Ameren's "significant" financial risk profile under our criteria.

[34] Ameren's SEC Form 10-Q Filing for the period ended March 31, 2012, p. 70.

> AM is a rate-regulated utility that serves 1.2 million electric and 126,000 gas customers in portions of central and eastern Missouri. The company also has 10,500 megawatts (MW) of generating capacity, of which 5,400 MW is base load coal and 1,200 MW is nuclear.
>
> AM's excellent business risk profile reflects its lower-risk, monopolistic rate-regulated utility businesses that provide an essential service. Additionally, the company's recent rate cases and regulatory mechanisms indicate an overall decreasing regulatory risk. In 2010 and 2011, the company received electric and gas rate case orders from the Missouri Public Service Commission (MPSC) that included more than $400 million of rate increases. In addition, the company also has credit-supportive trackers, including a fuel adjustment clause, pension and other postemployment benefit trackers, and a cost tracker for vegetation management and infrastructure inspections...
>
> Our corporate credit rating on AM marginally suffers from the company's affiliation with Ameren's nonrate-regulated competitive generation businesses...

Ameren's non-regulated businesses continue to hinder the ability of Ameren Missouri to achieve a higher credit rating from S&P. Although S&P indicates that Ameren's non-regulated operations only "marginally" hinder Ameren Missouri's credit rating, because Ameren Missouri's S&P credit rating is based on Ameren's consolidated risk profile, its credit rating is necessarily impacted by Ameren's non-regulated operations, which S&P currently rates 'BB-' with a Negative CreditWatch, which means it could be downgraded further. S&P stated the following about Ameren's business risk profile in its March 19, 2012, Research Report: "The consolidated strong business risk profile reflects the combination of the excellent business risk profiles of Ameren's regulated electric and gas utility businesses offset by the fair business risk of Ameren's competitive merchant energy business." Because S&P rates Ameren Missouri based on Ameren's consolidated credit profile, Ameren Missouri's S&P rating is clearly impacted by the risks associated with Ameren's non-regulated operations.

However, as explained previously, Moody's and Fitch tend to give more weight to Ameren Missouri's stand-alone risk profile. Although there is no consensus among the rating agencies on how much of an impact Ameren's non-regulated operations have on Ameren Missouri's credit quality, there is likely to be some trickle-down effect on Ameren Missouri's cost of capital due to its affiliation with these higher risk enterprises. Staff does not currently propose a downward adjustment to Ameren Missouri's cost of debt to reflect this trickle-down effect because the amount of the impact is debatable due to differing views on credit quality and the fact that there is currently only a one notch difference between Ameren's and Ameren Missouri's Moody's and Fitch credit rating. Although Staff did not make a downward adjustment to Ameren Missouri's cost of debt, Staff is not proposing to make an upward adjustment to the proxy group's cost of equity due to the credit rating differential between Ameren and Ameren Missouri as they compare to the average for the proxy group, due to Staff's concerns discussed above.

F. Cost of Capital

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

1. Capital Structure

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

Based on financial statements through March 31, 2012, Ameren Missouri has not issued any short-term debt since September 2009. This is the case in spite of the fact that Ameren Missouri has had construction work in progress ("CWIP") balances in the $600 million to $800 million range since January 1, 2011. Apparently, Ameren Missouri has been able to fund its liquidity needs through a March 2009 long-term debt issuance of $350 million and internal cash flows and balances. Staff will evaluate this situation further through the planned true-up proceeding in this case.

For the purposes of its direct case, Staff accepted Ameren Missouri's September 30, 2011, capital structure provided in the Direct Testimony of Company witness

Ryan J. Martin.[35] Schedule 6 presents Ameren Missouri's capital structure and associated capital ratios. The resulting capital structure consists of 53.02% common stock equity, 1.04% preferred stock and 45.94% long-term debt.

2. Embedded Cost of Debt and Preferred Stock

Staff also accepted the embedded cost of long-term debt and preferred stock provided by Ameren Missouri in response to Staff Data Request No. 0245.

3. Cost of Common Equity

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

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 55 market-traded electric utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to Ameren Missouri's regulated electric utility operations (*see* Schedule 7). Staff decided to add one additional criterion in this case as compared to Ameren Missouri's last rate case. Staff added a criterion to screen out companies that do not have an equivalent S&P business risk profile as Ameren Missouri, 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 as a "regulated" electric utility, many investment analysts, such as Goldman Sachs, consider Ameren to be a diversified company. Staff's criteria is as follows:

1. Classified as an electric utility by Value Line (55 companies);
2. Publicly-traded stock;

[35] Martin Direct Testimony, February 3, 2012, p. 5, lines 19-20.

3. Followed by EEI and classified by EEI as a regulated electric utility (19 companies eliminated, 36 remaining);

4. Followed by AUS and reporting at least 70% of revenues from electric operations (11 companies eliminated, 25 remaining);

5. Ten years of Value Line historical growth data available (3 companies eliminated, 22 remaining);

6. No reduced dividend since 2009 (2 companies eliminated, 20 remaining);

7. Projected growth available from Value Line and Reuters (1 company eliminated, 19 remaining);

8. At least investment grade credit rating (3 companies eliminated, 16 remaining);

9. Company-owned generating assets (0 companies eliminated, 16 remaining);

10. Rated an 'Excellent' Business Risk Profile by S&P (4 companies eliminated, 12)

11. No significant merger or acquisition announced in last 3 years (2 companies eliminated, 10 remaining).

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

b. The Constant-growth DCF

Next, Staff calculated Ameren Missouri's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[36] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12-months' dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the a weighted average of the 2012 and 2013 Value Line projected dividend per share (*see* Schedule 11) by the monthly high/low average stock price for the three months ending May 31, 2012 (*see* Schedule 10).[37] Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.1%, unadjusted for quarterly compounding.

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share ("DPS"), 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

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[36] 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.

[37] 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.

volatile.[38] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 9-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 8.00%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 6.96%. The average projected 5-year EPS annual compound growth rate estimates yielded a growth rate of 5.40%, which Staff believes is not sustainable (*see* Schedule 9-4, 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 its 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 cost of equity using a single-stage DCF methodology. However, if Staff uses growth rates consistent with these estimates in its constant-growth DCF, the cost of equity indication is approximately 9.10% to 9.60%.

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. 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.[39] As noted previously, long-term GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities should be much lower than the projected 5-year EPS growth rates.

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

[39] 2003 Mergent *Public Utility &* Transportation *Manual*, p. a15 – a18.

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,[40] 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 5.5%. 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 12). 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 investors to address 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 4.1% and a growth rate range of 5.0% to 5.5% -- a cost of common equity of 9.1% to 9.6% is implied (*see* Schedule 11).

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with

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

sustainable perpetual growth rates.[41] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for Ameren Missouri.

A multi-stage DCF may use either two or more 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 cost of common equity 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.[42]

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.[43] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 13-1 through 13-3). Based on this set of assumptions, Staff's estimated cost of equity for the proxy group is approximately 7.80% to 8.60%, mid-point of 8.20%.

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

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[41] 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.

[42] 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.

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

several years. However, in the context of discounting expected future DPS, it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for purposes of estimating the growth in DPS in a single-stage, constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own 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 5-year period, which is fairly conventional in multi-stage DCF analysis.

iv. Stage three

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

Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. Although in the last Ameren Missouri rate case, the Commission considered Staff's estimated perpetual growth rates of 3.00% to 4.00% to be too low, 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.[44] 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.[45] Because 1968 is consistent with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc., bankruptcy in December 2001. Considering that much of this disruption was caused by deregulation, Staff does not consider the information during this period to be informative for understanding investors' growth expectations for regulated electric utility operations.

Staff did not apply rigid selection criteria for purposes of selecting central 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

[44] 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.

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

the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major mergers, acquisitions and/or restructurings. Staff only included companies in which comparable data was available for each year of the period 1968 through 1999. The companies Staff selected are shown in Schedules 14-1 through 14-4.

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

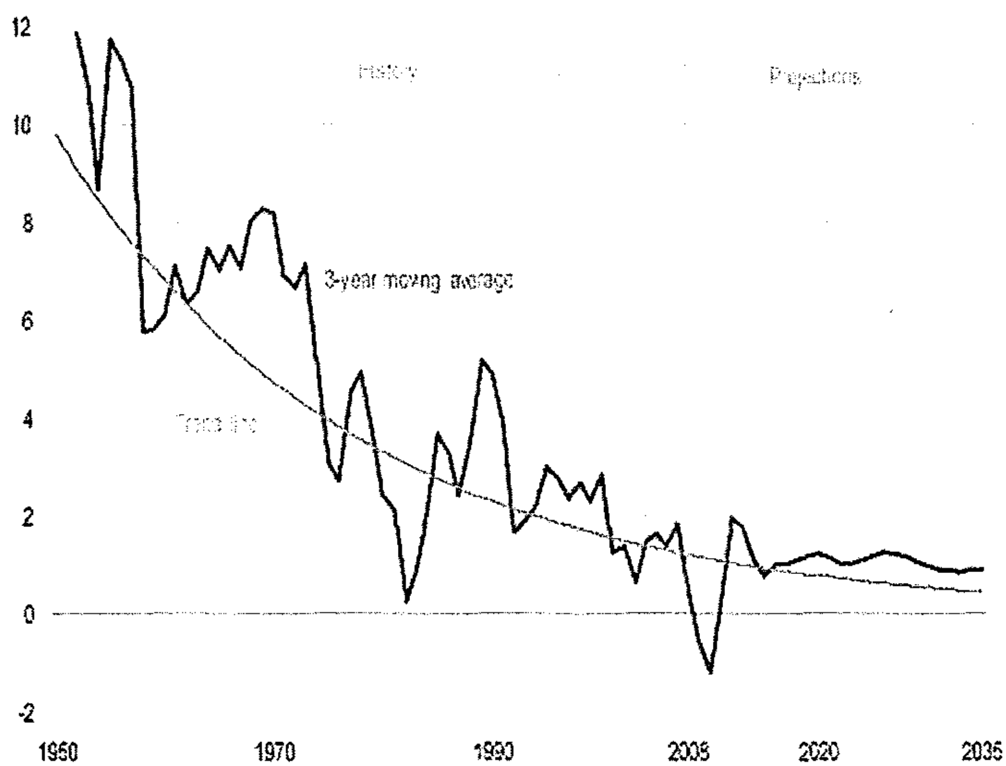
However, it is important to understand that these growth rates were achieved during a much more robust economic environment than the U.S. is expected to achieve in the foreseeable future. Also, it is interesting to note that the average growth rate for these electric utilities was less than 50% of GDP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

Also attached is Staff Schedule 15, which shows Staff's study of actual realized long-term growth of electric utility companies for the period 1947 through 1999 as published in the 2003 Mergent *Public Utility and Transportation Manual.* Although Staff 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

In the Commission's Report and Order in Ameren Missouri's last rate case, Case No. ER-2011-0028, the Commission dismissed Staff's estimated perpetual growth rates because they were lower than those used by the other ROR witnesses. As explained in the previous section of this report, Staff is using the same perpetual growth rates used in the last rate case based on data analyzed for the period 1968 through 1999. The Commission indicated that it appeared that Staff only relied on this period because this was the only data that was readily available to Staff. While Staff acknowledges it has certain resource constraints, Staff still 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 2011 Annual Energy Outlook:

Figure 59. U.S. elecricity demand growth 1950-2035
percent, 3-year moving average



Source: Energy Information Administration's 2011 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 hopes of addressing the Commission's 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.

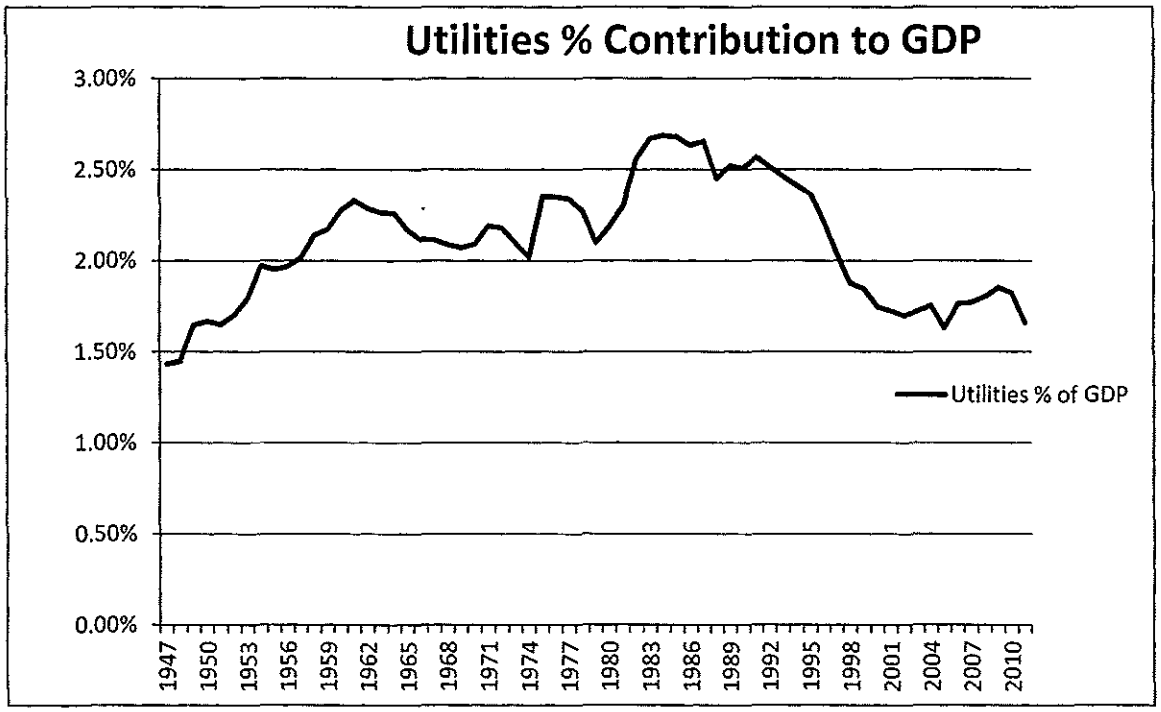
The other ROR witnesses in the last rate case estimated perpetual growth rates based on various estimates of long-term nominal GDP growth.[46] Specifically, the Company witness provided his own projected nominal GDP growth rate by analyzing historical data, whereas the Missouri Industrial Energy Consumers witness relied on the *Blue Chip Economic Forecasts.* While there may be some logic for this approach 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 cost of equity 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

[46] Nominal GDP includes economic growth caused by real factors, such as productivity improvements, technological advances and other factors that improve a country's overall standard of living, but it also includes expansion of the economy due solely to increases in the prices of goods and services, which is simply inflation.

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 16, 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. 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 Ameren Missouri 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. If utilities are to be able to continue 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.

Although the GDP data does show some relationship between aggregate GDP growth and utilities' contribution to aggregate GDP growth, it is interesting to note that the *total value added* from the utilities' sector grew faster than aggregate GDP for a period, but during its decline it grew at a rate slower than GDP on an aggregate basis. While Staff has not quantified the gross capital invested in the utility industry during the period of growth, it is generally recognized that the electric utility industry required significant capital investment in the late 1970s and early 1980s due to the construction of large generation facilities. Although the electric utility industry is currently in another construction cycle, it is not driven by demand growth, but by environmental requirements, transmission investments, and replacement of aging and/or polluting generating facilities. Because this construction cycle is not driven by growing demand, it would not appear that this growth could be sustainable, otherwise this investment would cause rates to spiral out of control, if allowed by commissions.

The *total value added* measurement of GDP includes increases to GDP caused by inflation. Because the period analyzed by Staff includes a high inflationary period during the late 1970s and early 1980s, it is misleading to assume utilities may be able to contribute as much to real GDP as it may to nominal GDP. Consequently, 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 compensation to employees, taxes on production and imports less subsidies, and gross operating surplus. Gross operating surplus includes consumption of fixed capital ("CFC"), proprietors' income, corporate profits, and business current transfer payments (net).[47] Although gross operating surplus could be used as a proxy for utilities' capital contribution to GDP, it seems the more relevant data would be that of corporate profits considering we are attempting to estimate the growth of shareholder value. Again, however, it should be noted that the corporate profit figure is an aggregate figure, which does not consider the dilution caused by the issuance of new equity. 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. 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 18). Staff was surprised to find that growth in corporate profits for SIC code 49 was as high as 20% in the early 1980s. This seemed to contradict the much lower electric utility industry per share growth rates published in the 2003 Moody's Public Utility Manual. 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 19). Although these per share growth rates were not as low those of the Moody's index, they were

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[47] http://www.bea.gov/glossary/glossary.cfm.

still 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 tested this theory by analyzing the aggregate growth rates of its Value Line *Central* region electric utility proxy group for the same period in which per share growth rates were analyzed (1969 – 1998). Staff found that the aggregate growth of earnings, dividends and book value of this proxy group was extremely tightly correlated (99%) to that of the utility industry's contribution to GDP growth. In fact, this proved to be a much tighter correlation than that of utility corporate profits, which had a correlation of 72%. Although aggregate utility growth has been lower than GDP growth since the early 1990s, the aggregate proxy group financial growth for the period 1968 through 1999 was 97% correlated to overall GDP growth.

While Staff believes the above correlations are more than coincidence, if Staff had access to more historical data for not only the *Central* region electric utilities, but also the *East* and *West* region electric utilities, these correlations could be tested further to ensure consistent relationships over time and over regions. Because we are testing the hypothesis that electric utilities' growth would converge toward the United States' estimated GDP growth, it seems logical to test this across regions. Additionally, a key weakness in the data Staff analyzed is that it does not extend past 1998. Staff deemed this necessary due to changes in the industry due to restructuring. However, Staff did extend the termination year for the aggregate financial growth figures for the companies in its *Central* region proxy group that continued to exist through 2010.

The correlations for the aggregate growth rates for the 5 remaining companies to that of the utility industry's contribution to GDP growth and to overall GDP growth were approximately 97% and 91%, respectively.

Although there have been some strong correlations between aggregate electric utility financial growth and utility and aggregate GDP growth rates, this has not translated into equivalent per share financial growth for the electric utility industry. This is extremely important to understand when estimating the cost of equity because this is what matters to investors and the analysts that advise them. Historical experience has shown the per share growth was approximately half of aggregate electric utility financial growth over the period analyzed (*see* Schedule 20). Consequently, even if the Commission accepts the hypotheses that electric utilities' growth may be dependent on aggregate GDP growth, historical financial evidence proves this does not translate into the same growth on a per share basis. Historical evidence indicates that these aggregate growth rates should be divided by two in order to consider the dilution experienced by electric utility shareholders. The resulting perpetual growth rate would be approximately 2% to 2.5%, which is lower than that which Staff used in its cost of equity estimate, but consistent with the perpetual growth rates used by equity analysts when valuing electric utility stocks.

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 from 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

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[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

an article, "Rethinking ROE: Rational estimates lead to reasonable valuations."[49] Kihm specifically addresses the recent common practice in utility rate cases of estimating the cost of equity 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.

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

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.

In the PUF article, Kihm also discusses the impact of dilution on expected growth rates for utilities by comparing Southern Company's 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%.[50] 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

[50] 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.

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. 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 cost of equity estimate. In Kihm's example, he uses an 8% cost of equity 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 cost of equity 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 cost of equity is the same 8% used by Kihm, then this would translate into an intrinsic value of $84, 66% higher than its current trading price. However, if one assumes a much more reasonable dividend growth rate of approximately 3% with the same cost of equity, then the intrinsic value of the stock would be $49.44, which is close to Kihm's estimate.

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_____ ** It is this clear-cut evidence that should be considered by the Commission when determining the reasonableness of certain projected growth rates for dividends in the long-run. In fact, because Ameren's non-regulated operations are expected to be a cash drain on Ameren's overall cash flow, it is likely that Ameren's regulated operations cannot provide investors with the full growth potential of the regulated utility operation. This causes investors to discount

Ameren's stock price, which causes a higher cost of equity than Ameren Missouri would otherwise be able to realize.

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vii. Preference for GDP Growth

Although Staff is confident that investors do not expect utilities' per share growth rates can 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 cost of equity. Consequently, Staff will provide a cost of equity 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 4.90% through 2022; EIA projects an annual compound growth rate of 4.4% 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 2.7% over the next ten years and the FOMC projects a central tendency long-term real GDP growth of 2.3% to 2.6%. In each case in which the sources do not project a nominal GDP growth rate, Staff recommends adding 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 4.3% to 4.9%. If the Commission chooses to use a GDP growth rate to estimate the cost of equity, Staff recommends the Commission use the lower end of the range (4.3%) 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 4.3% GDP growth rate in Staff's multi-stage DCF results in a cost of equity estimate of approximately 8.85%.

G. Tests of Reasonableness

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

1. The CAPM

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

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

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

For inputs, Staff relied on historical capital market return information through the end of 2010. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending May 30, 2012; that figure was 3.13%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 22). The average beta (β) for the proxy group was 0.69. 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.[51] 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 22. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.06% and 5.96%, respectively. While the cost of equity indication using the geometric average risk premium is more than likely below equity discount rates used to value utility stocks, Staff believes the 7.06% cost of equity 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, which puts pressure on the prices of these alternative, low-risk investments.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows an objective test of individual analysts' cost of equity estimates. Because this method is suggested in a textbook[52] 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 cost of equity 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%

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

[52] 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.

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 March, April and May 2012, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 4.92% and 5.52% respectively.[53] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 7.92% and 8.92%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 8.52% and 9.52%.

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, the average authorized cost of common equity for electric utility companies for the first quarter of 2012 was 10.84% based on 12 decisions. This number is high because it includes Virginia surcharge/rider generation cases that incorporate ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects. Excluding these Virginia surcharge/rider generation cases from the data, the average authorized electric utility ROE approximated 10.3% for the first quarter of 2012. The average authorized cost of common equity 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 quarter of 2012 was 8.00% based on 11 decisions. The average authorized ROR for electric utilities in 2011 was 7.95% based on 41 decisions (first quarter – 8.12% based on 13 decisions; second quarter – 8.01% based on 10 decisions; third quarter – 8.09% based on 7 decisions; fourth quarter – 7.61% based on 11 decisions).

While Staff understands the Commission's desire to review other commissions' authorized ROE's due to concerns about Missouri-jurisdictional utilities having to compete with

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

other utilities for capital, Staff would like to briefly explain why an allowed ROE is not indicative of a required ROE and the ability to attract capital. The primary consideration for attraction of capital is whether the current price of a given stock will result in the investor earning above, below or equivalent to their required return. For example, the allowed ROEs for many of Southern Companies' utility subsidiaries are typically much higher than the rest of the utilities in the country. However, this does not translate into higher realized returns for investors in Southern Company because the price of Southern Company's stock already reflects these high allowed ROEs. If this Commission were to award an ROE similar to those allowed for Southern Company's subsidiaries and hold all other ratemaking treatments constant, then current investors in the Missouri utility would achieve a return that was higher than their required return. However, after the increase in the Missouri utility's stock price, the investor and subsequent prospective investors would revert back to earning their required return. The opposite holds true if the Commission were to authorize an ROE below what is expected from the Commission. Consequently, setting allowed ROEs based on those allowed or earned for other companies may temporarily cause upward or downward pressure on the stock, but once this price correction occurs, the stock should experience "normal" capital attraction.

c. Equity Analysts

Past Commission decisions have expressed the view that the cost of equity used by equity analysts is not relevant to determining a reasonable cost of equity 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 cost of equity 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 cost of equity, investors do not make investment decisions with expediency as a 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 cost of equity. If the cost of equity 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 cost of equity that would be fair in setting the allowed ROE.

Rate-of-return witnesses often cite various academic studies to support their position that investors naïvely 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, the 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 investment 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 the analysts. Consequently, these predictions may well serve as acceptable proxies for general expectations and surely seem worthy of detailed analysis. (emphasis added)

In past rate cases, including Case No. ER-2010-0036, 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 cost of equity 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 cost of equity used by these very same analysts. Staff's experience has been that these equity discount rates are usually much lower than cost of equity 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 cost of equity. If allowed ROEs were set equal to the cost of equity, 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.[54]

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

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[54] The use of a real GDP growth rate for perpetual growth is consistent with Goldman Sachs' valuation approach discussed in the last 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.

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 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 Returns 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 cost of equity. While it is quite clear that Kihm believes the cost of equity 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 cost of equity for purposes of making investment decisions or for purposes of valuing utility assets or securities. Staff has performed extensive discovery in past rate cases that provide assurance that utility companies are not confusing the allowed ROE with the cost of equity. In fact, in the most recent Ameren Missouri rate case, Case No. ER-2011-0028, Staff discovered internal analysis performed by Ameren and Lazard, formerly known as "Lazard Freres," that clearly showed that Ameren is not making strategic corporate decisions based on this assumption.

It is also quite clear from Staff's analysis of equity analysts' reports that analysts do not expect commission to set the authorized ROE equal to the cost of common equity. Most equity analysts use a cost of equity 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 cost of equity 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 cost of equity, this may justify the decision to allow an ROE higher than the cost of equity. 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 cost of equity is lower than that which it chooses to authorize.

I. Demand-Side Investment Mechanism

As of the date Staff was preparing the ROR Section of this Staff Cost-of-Service Report, a stipulation and agreement had just been finalized in Ameren Missouri's Missouri Energy Efficiency and Investment Act ("MEEIA") Application, File No. EO-2012-0142. Therefore, it would be improper and premature to discuss this in detail in context of the Staff's Cost-of-Service Report. However, as Staff indicated in its Rebuttal Testimony in that case, Staff believes the Demand Side Investment Mechanism ("DSIM"), regardless of the final details, reduces Ameren Missouri's business risk. Unfortunately, it is very difficult to quantify in terms of basis points just how much the cost of equity may be reduced by the final mechanism. Most of the companies in Staff's proxy group already have demand side programs along with special recovery and incentive mechanisms to encourage these programs. Consequently, some of the impacts on the cost of equity of more favorable rate-making treatment for demand-side investments are already reflected in the stock prices of these companies. However, Staff believes the granting of the DSIM, coupled with the current high valuations on electric utility stock prices, i.e. low costs of equity, should more than support a Commission decision to allow an ROE for Ameren Missouri somewhere below 10%.

J. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover Ameren Missouri's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for Ameren Missouri in the range of 6.99% to 7.52% (*see* Schedule 23). This rate was calculated by applying an embedded cost of long-term debt of 5.885% and a cost of common equity range of 8.00% to 9.00% to a capital structure consisting of 53.02% common equity, 45.94% long-term debt, and 1.04% preferred stock. Because there appears to be some concern in setting an allowed return on equity based on the cost of equity, Staff recommends the Commission set the allowed ROE at 9.00% in this case. Although this is well-above what Staff believes the true cost of equity 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.

Staff Expert/Witness: David Murray

VII. Rate Base

A. Plant in Service and Depreciation Reserve

1. Accounting Schedule 3

This schedule has been adjusted, by account, to reflect the rate base value of Ameren Missouri's plant-in-service estimates through July 31, 2012. These estimates will be replaced with actual amounts following the true-up audit. The Staff adjusted Ameren Missouri's plant balances to allocate a portion of the Company's general plant to Ameren Missouri's retail natural gas business. These adjustments to the test year balances are reflected in Adjustments to Plant-In-Service Accounting Schedule 4.

Staff Expert/Witness: Erin M. Carle

2. Owensville Acquisition

The City of Owensville approved the sale of its electric distribution system in November 2011. During March 2012, Ameren Missouri purchased these electric distribution system assets. All plant in service and depreciation reserve amounts related to this acquisition have been included in Staff's Accounting Schedules 3 (Plant-in-Service) and 5 (Accumulated Reserve) in this case. Staff will continue to evaluate these values through the end of the July 31, 2012, true-up.

Staff Expert/Witness: Erin M. Carle

3. Plant-In-Service Accounting (Construction Accounting)

The Company requested that the Commission allow Ameren Missouri to implement a new regulatory mechanism called "Plant-In-Service Accounting" also called "construction accounting." Specifically, the Company seeks accounting authority to accrue for return and deferral of depreciation expense for all non-revenue producing plant additions in a regulatory asset during the period between the date when those assets begin serving customers until they can be reflected in rate base in a later rate case. In each future rate case, the Company would include these deferred amounts in its revenue requirement to be amortized over the lives of the underlying assets. Staff does not recommend wholesale application of construction accounting, and will discuss its specific opposition to this proposed regulatory mechanism in its rebuttal testimony.

Staff Expert/Witness: John P. Cassidy

4. Depreciation Reserve - Accounting Schedule 5

Accounting Schedule 5, Depreciation Reserve, has been adjusted by account to reflect the rate base value of Ameren Missouri's depreciation reserve estimates through July 31, 2012. These estimates will be replaced with actual amounts following the true-up audit. As it did with Plant in Service, the Staff adjusted Ameren Missouri's depreciation reserve balances to allocate a portion of the Company's general plant depreciation reserve to Ameren Missouri's retail natural gas business. These adjustments to the test year balances are reflected in Adjustments to Depreciation Reserve – Accounting Schedule 6.

Staff Expert/Witness: Erin M. Carle

5. Allowance for Funds Used During Construction (AFUDC) on Sioux Scrubbers

Ameren Missouri began construction of the Sioux Wet Flue Gas Desulfurization Project ("Sioux WFGD" or "scrubbers") during April 2005. The First Nonunanimous Stipulation and Agreement approved by the Commission in Ameren Missouri's rate case, Case No. ER-2010-0036, stated that Ameren Missouri could receive construction accounting for this project until costs were reflected in rates at the effective date of rates as part of its next rate proceeding or January 1, 2012, whichever occurred earlier. On September 3, 2010, Ameren

Missouri filed a subsequent application before the Commission seeking a rate increase as part of Case No. ER-2011-0028. As part of that rate case, the Commission established a July 31, 2011, effective date of rates. The scrubbers were installed at the Sioux station in a major construction project that was declared in service during November 2010. Most of these Sioux scrubber related construction costs were included in rate base in Ameren Missouri's Case No. ER-2011-0028. In this proceeding, the Commission must now determine whether construction accounting should be permitted to continue past the effective date of rates established in Case No. ER-2011-0028, July 31, 2011, for any costs related to the Sioux WFGD not already included in rates. Staff will also address certain other issues and adjustments regarding the Sioux WFGD Project construction accounting.

In Case No. ER-2010-0036, for purposes of computing depreciation rates, the Commision used a retirement date of September 2033 for the Sioux scrubbers. A corresponding depreciation rate was also established in that case. The Sioux scrubbers were not deemed in-service until November 2010. As such, Ameren Missouri did not begin its amortization period for the deferred depreciation expense and allowance for funds used during construction ("AFUDC") accrued during construction until the effective date of new rates approved in Case No. ER-2011-0028. The effective date of new rates approved in Case No. ER-2011-0028 by the Commission was July 31, 2011. The Company's response to MIEC Data Request No. 5.5 indicates the depreciation expense and AFUDC to be amortized over 266 months equals $45,069,631 as established by Commission Report and Order in Case No. ER-2011-0028. The Company's response specifically states, "Sioux Plant retirement date of September 2033 was used for depreciation rates implemented in PSC Case No. ER-2010-0036. The amortization period started in August 2011, therefore the amortizable life established was 266 months."

Based upon the information provided in response to MIEC Data Request No. 5.5, the monthly amortization related to the deferred depreciation expense and AFUDC calculated for the Sioux scrubber is $169,435. Ameren Missouri booked monthly amortizations for the months of August and September 2011 during the test year. Therefore, Staff proposes an adjustment of $1,694,429 to annualize the amortization related to the Sioux scrubbers as authorized by the Commission Report and Order in Case No. ER-2010-0036.

Staff also proposes an adjustment of $150,636 to add back the equity portion of AFUDC allowed for regulatory purposes, but removed from AFUDC for GAAP accounting purposes. In its response to MIEC Data Request No. 5.5, the Company states: "The Sioux scrubber construction accounting contra test year amount is being booked for GAAP accounting purposes only. Under GAAP accounting rules, only debt portion of interest expense can be capitalized for capital projects. FERC rules permit both the debt and equity portion of interest expense to be capitalized. The Sioux scrubber construction accounting contra regulated asset is the reversal of the equity portion for GAAP accounting. This is eliminated as it does not apply per FERC regulations." Ameren Missouri proposed this same adjustment in the same amount in its case.

In the First Non-Unanimous Stipulation and Agreement in Case No. ER-2010-0036, it states on Page 3, Item 5:

> 5. AmerenUE shall be allowed to continue to accrue Allowance for Funds Used During Construction ("AFUDC") on the wet flue gas desulfurization units ("scrubbers") AmerenUE is presently installing on the No. 1 and No. 2 generating units at AmerenUE's Sioux generating station, with the rate of return on equity ("ROE") adopted by the Commission in this case to apply to the equity component of that AFUDC. AmerenUE shall also be allowed to defer the depreciation expense (but no other Sioux scrubber related expense) of the Sioux scrubbers during the period commencing when the costs of the Sioux scrubbers are booked to plant-in-service and ending the earlier of: (1) the effective date of new rates in AmerenUE's next general rate proceeding or (b) January 1, 2012.

Staff's legal counsel advised that the intent of the language included in the First Non-Unanimous Stipulation and Agreement in Case No. ER-2010-0036 is to halt all accruals of deferred depreciation expense and AFUDC calculated on costs included in rate base in Case No. ER-2011-0028 related to the plant-in-service for the Sioux scrubbers at the earlier of the effective date of new rates in Case No. ER-2011-0028 or January 1, 2012. Based on this legal interpretation, Staff contends that all accruals of deferred depreciation expense and AFUDC related to the Sioux scrubber costs placed in rate base in Case No. ER-2011-0028 should cease at July 31, 2011. It is also Staff's position that any plant additions related to the Sioux scrubbers that were placed in-service after December 31, 2010 (the cut-off date for all plant in service related to the Sioux scrubbers in Case No. ER-2011-0028) but before July 31, 2011, are intended to accrue deferred depreciation expense and AFUDC as well although not explicitly stated in the *First Non Unanimous Stipulation and Agreement* in Case No. ER-2010-0036. As such, Staff is recommending an adjustment in the amount of $19,404, which represents the annualized deferred depreciation expense and AFUDC calculated for the period January 1, 2011 through

July 31, 2011, on all plant additions related to the Sioux scrubbers that occurred after December 31, 2010, but prior to August 1, 2011. The total deferred depreciation expense and AFUDC calculated for this time period is $402,629, to be amortized over a period of 249 months.

Staff Expert/Witness: Roberta A. Grissum

B. Cash Working Capital ("CWC")

1. Calculation of Revenue and Expense Lags

In certain instances, after examining the appropriateness of Ameren Missouri's revenue and expense lag cash working capital ("CWC") calculations, Staff has used the same revenue and expense lag factors as those recommended by the Company in this proceeding. In the situations where Staff determined that the lag the Company calculated was not appropriate, Staff developed a new lag based on available data provided in this rate case proceeding. Staff also adopted certain revenue and expense lags it calculated in Ameren Missouri's most recent rate case, Case No. ER-2011-0028, in which the test year was the twelve months ending March 31, 2010, with the true-up cut-off on February 28, 2011. For example, in this proceeding the Company developed its revenue collection lag using accounts receivable aging reports. However, Staff has instead adopted the revenue collection lag it developed in Case No. ER-2011-0028 (21.11 days), which was calculated based on an Ameren Missouri report specifically maintained for rate cases that calculated the actual period of time that the customers take to pay their bills. This report ("CURST 246 report") has been used by both Staff and the Company to determine the revenue collection lag in previous rate cases, and Staff believes that the data from that report provides a more accurate estimation of Ameren Missouri's collection lag than do accounts receivable aging reports. Almost half of the test year collection data in this rate case proceeding was also utilized to calculate the collection lag in Ameren Missouri's last rate case, Case No. ER-2011-0028. In addition, Ameren Missouri's response to Staff Data Request No. 0262 affirms that since the Company's last rate case, it has not made any changes to its billing and collections policies and procedures that would materially impact customer collections. For these reasons, the collection lag Staff recommended in Ameren Missouri's last rate case is still appropriate for use in this proceeding as well.

To further verify the accuracy of the Company's collection lag day recommendation based on accounts receivable aging analysis in this proceeding, Staff is also conducting a collection lag study of actual timing of customer collections, based upon a random customer sample. On May 7, 2012, Staff submitted Staff Data Request No. 0339 for access to customer billing and collections information for the test year, and received the Company's response on June 7, 2012, after an initial objection to Staff's request on May 17, 2012. Staff is currently reviewing the customer billing and collection data provided by the Company, and, given the large volume of data, has been unable to complete its review at this time. Staff will continue to examine this data as part of its true-up audit in order to determine if adjustments to its recommended revenue collection lag value are appropriate.

Staff and Ameren Missouri also differed on the calculation of Gross Receipts Tax ("GRT") expense lag. The Company calculated a 29.74 day expense lag for this item without factoring into its calculation the actual payment schedules for each of the taxing authorities. For gross receipts tax payments, the frequency of the payments varies (monthly, quarterly, semi-annually, or annually) and depends on the municipality to which the payments are being made. For some cities, payments are made on the last day of the following month, and for others, on the 20th day of the following month. Using the payment schedules of the municipalities that collect GRT from Ameren Missouri, Staff calculated a 48.04 day expense lag for GRT.

Staff will continue to examine CWC through the true-up period ending July 31, 2012, to determine if further adjustments to the cost of service are necessary to address revenue and expense lags.

Staff Expert/Witness: Kofi Agyenim Boateng

C. Prepayments and Materials and Supplies

The Company has utilized shareholder funds for prepaid items such as insurance premiums and materials and supplies. By including these items in rate base, this up-front investment made by the Company is recognized in customer's rates.

During the test year, in May 2011, the lease for the freight on coal cars expired. Staff has eliminated this item from its calculations as this lease will not be renewed in the future. The lease for imaging software also expired during the test year in November 2010. However, the Company has indicated to Staff that a new lease for imaging software was signed in May 2012.

Staff has requested a copy of the new lease for imaging software and will review this item during its true-up analysis in this case. Staff has included prepayments in Accounting Schedule 2, Rate Base, at the 13-month average level ending April 30, 2012.

The Company also maintains a variety of materials and supplies in inventory to meet its day-to-day needs in performing its utility operations. Staff has included Ameren Missouri's average balance of materials and supplies inventory that was maintained during the 13 months ending April 30, 2012, in Accounting Schedule 2, Rate Base. The level of both materials and supplies and prepayments will also be re-examined as part of Staff's true-up audit.

Staff Expert/Witness: Erin M. Carle

D. Customer Deposits

Customer deposits represent funds received from Ameren Missouri's customers as a security against potential loss arising from failure to pay for utility service received. Until refunded, customer deposits represent a source of funds available to the Company and are included as an offset to the rate base investment. Generally, interest is calculated on customer deposits and paid to the customers for the use of their money. The amount of customer deposits in Accounting Schedule 2, Rate Base, represents a 13-month average (April 2011-April 2012) of Ameren Missouri's customer deposits. In Accounting Schedule 10, Staff adjusted expenses to include interest calculated on Staff's level of customer deposits reflected in rate base.

Staff Expert/Witness: Erin M. Carle

E. Customer Advances

Customer advances are funds provided by individual customers of the Company to assist in the costs of the provision of electric service to them. These funds represent interest-free money to the Company. Therefore, it is appropriate to include these funds as an offset to rate base. No interest is paid to customers for the use of their money, unlike customer deposits. The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents a 13-month average (April 2011 - April 2012).

Staff Expert/Witness: Erin M. Carle

F. Fuel Inventories

Staff included a 13-month average of coal inventory through April 30, 2012, adjusted to reflect coal prices that will be in effect as of July 31, 2012. Staff also utilized a 13-month average through April 30, 2012, to determine the inventory amount for oil. For nuclear fuel inventory, Staff used an 18-month average of the value of the nuclear fuel that was contained in the fuel core of the Callaway Nuclear Generating unit through April 2012. For stored natural gas, Staff utilized a 13-month average through April 30, 2012, to determine the quantity stored and determined its value utilizing the latest known and measurable pricing information which reflects the current trend in gas prices. Staff will continue to examine the actual inventory quantities for all of these items through the end of the true-up period on July 31, 2012. Staff will also re-examine natural gas prices on July 31, 2012, the end of the true-up cut-off established by the Commission in this case.

Staff Expert/Witness: Lisa K. Hanneken

G. Demand-Side Management Cost Recovery Regulatory Asset

1. Ameren Missouri's "Cycle 1" Demand-Side Management Programs

Ameren Missouri began implementing demand-side management ("DSM") programs in February 2009 for energy efficiency programs contained in the Company's then-adopted preferred resource plan which was filed on February 5, 2008, in Case No. EO-2007-0409. Ameren Missouri's "Cycle 1" DSM programs (four business energy efficiency programs and five residential energy efficiency programs) were each first offered to customers in 2009 and were each terminated on September 30, 2011. Ameren Missouri also had one voluntary demand response program (Rider L Peak Power Rebate) which was effective from July 9, 2009, to December 31, 2011. Rider L was utilized during the summer of 2009 but was not utilized during the summer of 2010 or during the summer of 2011. Attached to this Staff COS Report as Appendix 3, Schedule JAR-1 are pages from Staff's recent Status Report[55] which highlight the

[55] See File No. AO-2011-0035, item number 6, filed on January 4, 2012.

Ameren Missouri DSM Quarterly Stakeholder Group[56] process, Ameren Missouri's implemented and planned DSM programs and the challenges and successes of Ameren Missouri's DSM programs.

The energy and demand impacts and the overall delivery processes of Ameren Missouri's DSM programs are evaluated, measured and verified by third-party contractors chosen and paid for by Ameren Missouri. Ameren Missouri's "Cycle 1" evaluation, measurement and verification ("EM&V") reports for all of its DSM programs were provided to the Company's DSM Stakeholder Group members in May 2012.

2. Ameren Missouri's "Bridge" DSM Programs

Ameren Missouri currently offers five "bridge" DSM programs (two business energy efficiency programs and three residential energy efficiency programs), [57] which the Company plans to offer until it can transition to Commission-approved MEEIA of 2009 DSM programs.[58] The business "bridge" programs became effective on November 24, 2011, and the residential "bridge" programs became effective on December 18, 2011. All "bridge" DSM programs terminate on September 30, 2012, and are limited by the Company's goal of reducing a total of 30,000 MWh of energy usage through the "bridge" programs. Should the Commission approve the *Unanimous Stipulation and Agreement Resolving Ameren Missouri's MEEIA Filing* filed on July 5, 2012 in Case No. EO-2012-0142, it is expected that Ameren Missouri will extend the term of its "bridge" DSM programs until early 2013 when it transitions to its Commission-approved MEEIA DSM programs.

Ameren Missouri's "bridge" programs' EM&V reports will be provided to the Company's DSM Stakeholder Group members within four months of the termination date of the "bridge" DSM programs.

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

[57] Business Standard Incentive Program, Business Custom Incentive Program, Residential Lighting Program, Residential Multifamily Income Qualified Program, and Refrigerator Recycling Program in MO.P.S.C. Schedule No. 5, Sheet Numbers 225 through 258.

[58] Case No. EO-2012-0142 contains Ameren Missouri's January 20, 2012, requests for approval of eleven DSM programs and for approval of a demand-side programs investment mechanism ("DSIM") under MEEIA and the Commission's MEEIA Rules: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.

3. Staff Recommendation

Staff recommends that the Commission order the continuation of the current Ameren Missouri DSM regulatory asset cost recovery mechanism[59] for the "Cycle 1" DSM programs and for the "bridge" DSM programs.

Staff Expert/Witness: John A. Rogers

4. DSM Costs Included In Rate Base

In prior rate proceedings, Ameren Missouri was allowed to treat DSM program expenditures as a depreciable asset through booking the amounts to a regulatory asset account and accruing a carrying charge equal to Ameren Missouri's AFUDC rate on the balance.[60] A new DSM regulatory asset was created in each rate case. In Case No. ER-2008-0318, one-tenth of the program cost amount Ameren Missouri spent through September 30, 2008, was included in the cost of service through a ten-year amortization. In Case No. ER-2010-0036, $11,430,501, the balance in the regulatory asset as of December 31, 2009, less the Residential Lighting and Appliance program costs, was included in rate base and an annual amortization based on six years was included in expense. In Case No. ER-2011-0028, DSM program costs expenses incurred through February 28, 2011, in the amount of $28,547,631, was included in Ameren Missouri's rate base and an annual amortization of that amount (again, less Residential Lighting and Appliance program costs) based on six years was included in expense.

In this proceeding, consistent with past Staff practice, $33,905,016 of DSM program costs incurred since February 28, 2011, the true-up cut-off date in Ameren Missouri's last rate proceeding, Case No. ER-2011-0028, has been included in Staff's rate base. One-sixth of that amount has been included in expense through a six-year amortization.

For ease of presentation, Staff has combined the unamortized portion of all previous Ameren Missouri DSM regulatory assets included in rate base into one rate base item in this case labeled "Energy Efficiency Regulatory Asset." Staff's adjustment to amortization expense was

[59] In Case No. ER-2010-0036, as a result of the First Nonunanimous Stipulation and Agreement, the balance of the regulatory asset for prudently incurred programs' costs was included in rate base and an annual amortization based on six years was included in expense. In Case No. ER-2011-0028, the Commission approved the continued use of the regulatory asset cost recovery mechanism it had approved in Case No. ER-2010-0036.

[60] "AFUDC" is Allowance for Funds Used During Construction.

determined by combining a full year's amortization expense for each previously authorized DSM regulatory asset, and comparing the result to Ameren Missouri's test year DSM regulatory asset amortization expense.

Staff Expert/Witness: Mark L. Oligschlaeger

H. FAS 87 – Pensions and FAS 106 OPEBs Trackers

See the discussion in Section IX.D. - Payroll and Benefits, subsections 6.a. and 7.a.

Staff Expert/Witness: Roberta A. Grissum

I. Accumulated Deferred Income Taxes

Ameren Missouri's deferred tax reserve represents, in effect, a prepayment of income taxes by Ameren Missouri's customers to the Company prior to payment being made by the Company to taxing authorities. As an example, because Ameren Missouri is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, the depreciation expense deduction used for income taxes paid by the Company is considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to the Company. Therefore, Ameren Missouri's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. As part of its true-up audit, the Staff will re-examine Accumulated Deferred Income Tax ("ADIT") balances to make sure all items included in those balances are consistent with the other components of the cost of service and that they reflect the current balances at the true-up cutoff date, July 31, 2012. Based on this true-up examination, Staff may make additional adjustments to the cost of service as necessary.

Staff Expert/Witness: John P. Cassidy

VIII. Allocations

A. Review of need for Missouri Jurisdictional Allocations Factors

The traditional method for determining the costs allocated to the retail jurisdiction to determine the retail cost of service is accomplished by applying a retail jurisdictional allocation factor to the utility's total amount of investments and expenses. The retail cost of service is then compared to the retail revenues generated by the current effective retail rates to determine the additional revenue and incremental rate increase for retail customers. Thus, the retail jurisdiction and the wholesale jurisdiction are allocated both rate base and expense costs. Any wholesale revenue the utility receives from municipalities is excluded in the determination of the utility's retail revenues.

In the current case when Ameren Missouri determined its retail revenues, it did not recognize either the existence of the municipal customers' contracts or the municipal customers' generation requirements on Ameren Missouri's system. Instead, Ameren Missouri has included revenue from wholesale municipal customers as off-system sales based upon actual wholesale contractual rates. Ameren Missouri has also included the generation costs to serve those wholesale customers as additional fuel and purchased power expense.

The Staff performed an analysis that determined that reflecting wholesale revenues received from the four municipalities as off-systems sales and flowing those off-system sale revenues and costs through to the fuel adjustment clause appears to be reasonable for this case. In general, the Staff is not opposed to departing from the traditional jurisdictional allocation method of determining the retail cost of service. However, the Staff will continue to analyze this treatment on a case by case basis going forward in all future Ameren Missouri rate proceedings.

Staff Expert/Witness: John P. Cassidy

B. Corporate Allocations

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

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

The Company provided Staff with data regarding its allocations through May 2012 for review, as well as copies of the internal audit reports required by the ICC. While Staff is not recommending an adjustment at this time, Staff will need to examine the allocation of AMS costs to Ameren Missouri's electric operations through the true-up period ending July 31, 2012, to determine if any significant changes have or will take place subsequent to the May 2012 data provided.

Staff Expert/Witness: Kofi Agyenim Boateng

IX. Income Statement

A. Rate Revenues

1. Introduction

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

One of the major tasks in a rate case is not only to determine whether a deficiency (or excess) between cost of service and operating revenues exists, but also to determine the magnitude of any such deficiency (or excess). Any deficiency (or excess) identified can only be made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues) prospectively, on a going-forward basis.

Staff Expert/Witness: Roberta A. Grissum

2. Definitions

Operating Revenues are composed of Rate Revenue, Revenue from Off-System Sales and Other Operating Revenues. Each is defined respectively as follows:

Rate Revenues: Test year rate revenues consist solely of the revenues derived from the current rates Ameren Missouri charges for providing electric service to its Missouri retail customers (i.e., native load and customer charges). Ameren Missouri charges are determined by multiplying each customer's usage by the per unit rates established in its tariff. Missouri retail customers are charged summer rates (June – September) and winter rates (October – May) during the year. These charges are broken down for Missouri retail customers into two categories: (1) a demand charge; and (2) an energy charge. Missouri retail customers' rates are also broken down by rate class based upon type and amount of usage. These rate classes include: (1) Residential Services ("Res"); (2) Small General Services;("SGS") (3) Large General Services ("LGS"); (4) Small Primary Service ("SPS"); (5) Large Primary Services ("LPS"); (6) Large Transmission Service ("LTS") and (7) Public and Private Lighting. In addition to these rate classes, there is a separate category for Metropolitan Sewer District ("MSD"). Revenues from the fuel adjustment clause ("FAC") represent collections or refunds of prior period fuel costs and are excluded in determining the annualized level of ongoing rate revenues.

Revenue from Off-System Sales: Revenue from off-system sales is realized as a result of Ameren Missouri's sales of electricity to other utilities at non-regulated prices. The gross revenues from these sales, less the generation or purchased power expense incurred by Ameren Missouri to make these sales, is known as the profit margin on off-system sales. The rationale for assigning this profit to ratepayers and including it in operating revenues is that the electricity sold by Ameren Missouri is generated by power plants being paid for by the ratepayers through electric rates charged by Ameren Missouri.

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

Staff Expert/Witness: Roberta A. Grissum

3. The Development of Rate Revenue in this Case

The objective of this section is to determine annualized, normalized test year usage and revenues by rate class.

The intent of Staff's adjustments to test year Missouri usage 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 test year (in this case, updated through January 31, 2012, as explained below).

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

Staff Expert/Witness: Curt Wells

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Adjustment to Remove Unbilled Revenues

Staff has eliminated unbilled revenue from its determination of revenue requirement to ensure only 365 days of revenue is included and to reflect revenues stated on an "as billed" basis. The recording of unbilled revenue on the books of the Company recognizes sales of electricity that have occurred, but have not yet been billed to the customer. Therefore, it is necessary for Staff to remove unbilled revenue in order to reach an accurate revenue requirement based upon electricity sales billed to and revenues collected from Missouri ratepayers.

Staff Expert/Witness: Roberta A. Grissum

b. Adjustment to Remove Gross Receipts Tax

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

Staff Expert/Witness: Roberta A. Grissum

c. Preliminary Adjustments to Test Year

Starting with revenue based on Revenue Month (the month in which usage and revenue were reported in the Company billing system), Staff adjusted Ameren Missouri's revenue in all rate classes to reflect Ameren's revenues as Primary/Rate Month (the month reflecting the rates and revenue in the month when the majority of service actually occurred). This adjustment was necessary to move re-billed amounts (negative and positive) to the month where the energy was actually used.

Staff Experts/Witnesses: Curt Wells and Seoung Joun Won

d. 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 January 31, 2012, and should include minor billing adjustments.

Staff Experts/Witnesses: Curt Wells and Seoung Joun Won

e. Large Customers Annualization

LPS Rate Class – Staff made adjustments to billing units and revenues based upon an "update period" of February 1, 2011, through January 31, 2012, to be adjusted for known and measurable changes through the true-up period July 31, 2012. There were 72 customers in the LPS rate class during the update period. Staff performed a data check for billing corrections prior to doing other adjustments. Staff annualized LPS customers on an individual customer (account) basis. Staff examined each LPS customer's individual monthly demand and energy use, measured over multiple years prior to the update period and the twelve (12) months of the update period, graphically to determine if an adjustment was needed to reflect an annualized/normalized level of demand and energy use for the 12-month update period, as well as to identify the type of adjustment required to reflect the appropriate annualized/normalized level.

There were no adjustments to revenues for the Economic Development Rider ("EDR"). This rider provides for discounts to be "paid" to customers (in the form of credits on their electricity bill) who locate or expand operations in certain areas of Ameren Missouri's service territory. EDR credits are provided to the customer over a five-year period. The value of the credits is a declining percentage of the customer's electric bill calculated on the appropriate general application rate schedule. Usually, these discounts are included in the determination of Ameren Missouri's revenues because fostering economic development is assumed to be a benefit to all ratepayers. As of the end of the update period, there are no EDR customers. Therefore, Staff included no EDR discount to revenues in this rate case.

The other LPS adjustments are as follows:

(a) Interclass Rate Switching Adjustment

No customers moved into or out of the LPS rate class from other classes during the update period. Therefore, Staff made no adjustments to billing units and revenues for interclass rate switching.

(b) Annualization

The general intent of an annualization is to restate update period billing units results as if conditions known at the end of the update period had existed throughout the entire time period considered. Staff reviews each of the very largest customers to determine if adjustments need to be made to reflect any major growth or decline in kWh usage and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers. During the update period in this rate case, one existing customer started to receive service under Rider B,[61] and one new customer was added to the LPS class. Staff annualized these customers' billing units and revenues for all twelve (12) months.

(c) 365-Days Adjustment

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

Staff Expert/Witness: Seoung Joun Won

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[61] The existing customer will be taking service at a different voltage and Rider B discount for service at 34.5 kV or higher. Rider B is a discount applicable for service to substations owned by customer in lieu of company ownership.

LTS Rate Class - There was only one customer on the LTS rate class. The only adjustment made to the LTS customer was an annualization for the rate increase that occurred during the update period.

Staff Expert/Witness: Seoung Joun Won

f. Annualization for Rate Change

The rates approved in Case No. ER-2011-0028 were effective July 31, 2011. Therefore rate revenues prior to July 31, 2011, are based on the rates that were in effect prior to Case No. ER-2011-0028. Thus, update period revenues are understated by the difference between the amount that was actually billed to customers during the update period and the amount that would have been billed to customers by the Company if the current rates (effective July 31, 2011) had been in effect throughout the entire period. Staff's method of computing annualized revenues for each rate class is to multiply update period billing units by current rates. The difference between these computed annualized revenues and the amounts billed during this period under the prior rates provide the amount of the Annualization for Rate Change Adjustment.

Staff Expert/Witness for LPS and LTS classes: Seoung Joun Won

Staff Expert/Witness for all other classes: Curt Wells

g. Weather Normal Variables

Historical Data Used to Calculate Normal Weather Variables - Each year's weather is unique; consequently, usage, hourly loads, revenue, and fuel and purchased power expense need to be adjusted to "normal" weather. Staff used weather observations for the update period of February 1, 2011, through January 31, 2012, from the Lambert - St. Louis International Airport ("STL"), 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[62]. To conform to the NOAA's

[62] Retrieved on April 17, 2012 from NOAA website, http://www.aos.wisc.edu/~sco/normals.html.

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, on which NOAA bases its calculation of 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 the instrument's environment may also occur during the 30-year period. NOAA specifically identified three major instrument and location changes for STL in 1989, 1996 and 2002 during the 30-year period of 1981 - 2010. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011. Staff verified the adjustments for anomalies in the STL time series by direct communication with NCDC and through its own review of the daily observations. NCDC confirmed that 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 provided a peer-reviewed, published paper[63] to explain the meteorological and statistical soundness of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies.

This is the first Ameren Missouri rate case in which Staff has used NOAA's normal weather based on the 30-year period of 1981 – 2010. In Ameren Missouri's previous four electric cases, Staff and Ameren Missouri agreed to adjust temperature data from NOAA in the 30-year period (January 1, 1971 – December 31, 2000) for the St. Louis Lambert Airport weather station based on a merger case and complaint case agreement in Case No. EM-96-149 and Case No. EC-2002-1. The adjustments agreed to were necessary because NOAA's previous normals did not take into account a 1996 instrumentation change. However, NOAA's new normals 1981-2010 published in July 2011 accounted for not only the 1996 instrumentation change but also instrumentation changes in 1989 and 2002.

According to the NCDC calculation, there are three major adjustments to the historical monthly minimum temperature time series for 1981 through 2010. First, in January 2002, a change of the instrument elevation occurred that resulted in monthly average minimum

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

temperature values around 0.7° F warmer than before, so NCDC adjusted upward the observations from 1981 to 2002. Second, in June 1996, a change occurred that resulted in minimum temperature values around 1.6° F cooler than before, so NCDC adjusted downward the observations from 1981 to 1996. Finally, in March 1989, a change occurred that resulted in minimum temperature values that were around 1.2° F warmer than before, so NCDC adjusted upward the observations from 1981 to 1989. Cumulatively, NCDC identified the average of the correction value of approximately 0.3° F for the time period 1981-1989, approximately -0.9° F for the time period 1989-1996, and approximately 0.7° F for the time period 1996-2002 to the historical monthly minimum temperature time series. NCDC found no anomalies requiring significant adjustment in the maximum temperature time series. Staff presents NCDC's charts of the unadjusted and adjusted minimum and maximum temperatures STL data series in Staff's Appendix 3, Schedule SJW-1 and SJW-2, respectively.

Because Staff uses daily temperature observations to calculate normal weather values, it 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 STL temperature variables required to weather-normalize sales are the test-year actual and the 30-year normal two-day weighted daily mean temperatures. The day's daily mean temperature is 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.[64]

This was done because yesterday's weather effects how electricity is used today. For example, if yesterday was hot and the air conditioner was on, it is more likely that the air

[64] To calculate the Dth day's two-day weighted mean temperature ($TWMT_D$), the current day's (D) daily mean temperature (DMT_D) is averaged with the prior day's (D-1) daily mean temperature (DMT_{D-1}), applying a 2/3 weight on the current day and 1/3 weight on the prior day: $TWMT_D = (2/3)\ DMT_D + (1/3)\ DMT_{D-1}$.

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 STL 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 results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

Because actual temperatures do not smoothly move up and down from day to day during the year,[65] Staff assigned these normal temperatures to the days of the update period based on the rankings of the actual temperatures of the update period.

This information was provided to Staff witness Shawn E. Lange for weather normalization of the test year kWh usage and update period hourly loads.

Staff Expert/Witness: Seoung Joun Won

h. Weather Normalization of Usage

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature reaches higher levels, the demand for cooling, air conditioning and fans increases the 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 Ameren Missouri's service territory, therefore, it follows that Ameren Missouri's electric load is linked with and responsive to temperature.

Ameren Missouri's test year ran from October 1, 2010, through the end of September 2011. In an attempt to capture a more likely forward-looking indictor of non-weather

[65] 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.

electricity usage per customer, Staff determined to use the most recent temperature and load data available and, therefore, based its analysis on an updated period of February 1, 2011, through January 31, 2012.

December 2011 and January 2012 experienced temperatures warmer than normal resulting in electric energy usage below that which would have been expected under normal weather conditions. May through August 2011 experienced temperatures warmer than normal resulting in usage above that which would have been anticipated under normal conditions. The month of February 2012 saw temperatures cooler than normal, which resulted in higher usage of electric energy than would have been anticipated under normal weather conditions. Since the temperatures in the twelve month updated period ending January 31, 2012, used by Staff deviated from normal, and since Staff chose a more recent time period to review than the one used by Ameren Missouri, Staff performed its own weather impact analysis. However, the method and model used by Staff is similar to those used by Ameren Missouri.

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

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

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

Staff Expert/Witness: Shawn E. Lange

i. Weather Normalization of Revenue

Staff normalized update period usage data provided by Ameren Missouri for the Res, SGS, LGS, and SPS rate classes for weather by applying weather normalization factors provided by Staff witness Shawn E. Lange for each class for each month. Staff adjusted the billing units by these factors, and applied current rates to determine weather-normalized revenue. The difference between these weather-normalized revenues and the update period revenues determined the amount of the Weather Normalization Adjustment.

Staff Expert/Witness: Curt Wells

j. 365-Days Adjustment to Usage of Weather Sensitive Classes

Staff calculated a normalization adjustment to Ameren Missouri's kWh usage to reflect a calendar year's (i.e., 365 days') worth of usage. Ameren Missouri's customers' usage is measured and rate revenue are collected over a period known as a revenue month, which is the interval over which Ameren Missouri reads customers' meters and issues bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months. Revenue months take their names from the calendar month in which the customer's bill is rendered. For example, assume a customer's meter was read and usage determined on June 8 and then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for this bill is July even though 22 days of the usage measured for this bill occurred from June 9 through June 30 and it contained only eight days of usage in July.

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than or less than the number of days for the same-named calendar month. For the example given above, the usage is for 30 days (June 9 through July 8), even though the revenue month is July, which has 31 days. When revenue month usage is totaled over the year, the resulting revenue year will include usage from the immediately prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain more than or less than 365 days' usage. Therefore, since the costs and expenses are accounted over a calendar year, Staff calculates an annualization adjustment to bring the revenue year kWh into a 365-days interval. This adjustment is stated in kWh and is referred to as the 365-Days Adjustment.[66]

Staff calculates the 365-Days Adjustment by subtracting the weather-normalized revenue month kWh from the weather-normalized calendar month kWh for the test year; the difference, or the 365-Days Adjustment, may be either positive or negative.

The 365-Days Adjustment for the weather-sensitive classes were provided to Staff witness Curt Wells, who used the 365-Days Adjustment to adjust the revenues of the weather- normalized class revenues months to the twelve months ended January 31, 2012.

Staff Expert/Witness: Shawn E. Lange

k 365-Days Adjustment to Revenue (Weather Sensitive Classes)

As described above, since billing months are an aggregation of bill cycles, they will differ from calendar months in the time period they cover. To adjust revenue for this difference, Staff allocated the kWh days adjustment calculated by Staff witness Mr. Lange proportionately to the appropriate monthly kWh usage for each class and applied current rates to arrive at the 365-Days Adjustment to revenue.

Staff Expert/Witness: Curt Wells

l. Adjustment to Annualize Energy Efficiency Programs' Impact on Test Year Usage

Ameren Missouri is requesting, for the first time, an adjustment to annualize the impact of its energy efficiency programs on test year usage. The Company has updated its analysis[67] using information from its more current tracking reports available for an update period of February 1, 2011, through January 31, 2012, for consistency with the other normalization and annualization adjustments that Staff is making to the usage that revenue requirement is based on. Using its methodology and "class level load shapes," Ameren Missouri estimates the impact on test year sales, due to the updated adjustment amounts to annualize energy efficiency programs, to be 22,795,268 kWh for the residential rate class and 132,875,944 kWh for the remaining rate classes, i.e., SGS, LGS, SPS, and LPS.

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[66] 365-Days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

[67] Staff's Data Request No. 0255

Staff supports Ameren Missouri's energy efficiency annualization adjustment in this case and agrees that it should be recalculated for the true-up of the revenues in this case. However, as further explained below, Staff recommends that the Commission order Ameren Missouri to use "end-use load shapes" when calculating an adjustment to annualize energy efficiency programs' impact on test year sales in future general electric rate cases unless it can demonstrate why use of "end-use load shapes" is not feasible and/or cost-effective. An explanation of the adjustment follows.

Any energy efficiency measure installed as a result of the Company's energy efficiency programs during the update period, but not installed on the first day of the update period, will not have the full impact of usage reduction reflected in the test year weather-normalized usage. To realize this, an adjustment is made to annualize the full impact of the energy efficiency measure on update period sales. Because the Company has records for all of its energy efficiency programs' measures installed in the update period, the expected annualized energy savings for each measure, and the installation date for each measure, it is possible to estimate an adjustment to test year usage to annualize the impact of all energy efficiency measures installed during the test year. The Company's proposed adjustment to annualize energy efficiency programs' impact on test year usage is analogous to adjustments typically made by the Company and Staff to produce a level of usage that would have occurred if every customer on the Company's system at the end of the update period had been on the system for the entire test year.

Using tracking reports maintained by the Company and its energy efficiency programs' implementation contractors, the Company assessed the number of each type of energy efficiency measure installed in each month of the test year. For each type of measure installed in a given month of the test year, the Company calculated the actual impact of that type of measure on the test year usage assuming each type of measure was installed "mid-month" and compared that impact to the annualized impact for that type of measure from the tracking reports.

To calculate the impact of each energy efficiency measure type on Ameren Missouri's hourly loads, Ameren Missouri utilized an assumed pattern of consumption for each measure based on "class level load shapes" from the Company's most recent Integrated Resource Plan ("IRP"), Case No. EO-2011-0271. Staff has reviewed the Company's workpapers for its adjustment to update period usage and has met with the Company to better understand the methodology it used. With this type of allocation to the hours, the estimated impact on each hour would be a function of the magnitude of the loads in that hour. For example, this method would allocate more savings from a residential lighting program to the hot summer afternoon hour than it would to the 10:00 pm hour. As a result of its review and meetings with the Company, Staff has determined that the use of "end-use load shapes" that estimate the hourly impact on loads from the Company's most recent IRP could have been used. With this type of allocation to the hours, the estimated impact on each hour would be based on the contribution of that end-use for that hour. For example, this method would allocate more savings from a residential lighting program to the hour ending at 10:00 pm on a summer day than it would to the 4:00 pm hour because that is when the savings from the lighting measures actually occur. Therefore, "end-use load shapes" would likely improve the accuracy of an estimated adjustment to annualize the energy efficiency programs' impact on test year sales, especially on the amount of off-system sales ("OSS") that could be made since the customers are no longer using as much energy.

In response to a request from Staff, the Company recalculated the impact on OSS revenue from using "end-use load shapes" rather than "class level load shapes" for the residential HVAC program impacts. The Company estimated that the impact to OSS revenues is about $2,000, or about 4% of the total OSS revenues associated with the residential HVAC program. If the Company assumed that the same 4% would apply to every energy efficiency program, the Company estimates the total potential difference would be around $200,000.[68]

Ameren Missouri is planning on increasing its energy efficiency programs if the Commission approves its MEEIA filing, which should result in greater energy savings in the future. Therefore, Staff recommends the Commission order Ameren Missouri to use "end-use load shapes" when calculating an adjustment to annualize energy efficiency programs' impact on test year sales in future general electric rate cases unless it can demonstrate why use of "end-use load shapes" is not feasible and/or cost-effective. Staff appreciates the Company's attention to detail in calculating the energy efficiency annualization adjustment that it has proposed in this case. Staff also realizes that using "end-use load shapes" to allocate the energy savings to the hours will require a significant amount of resources but, in theory, it will give a more accurate estimate of the actual impact of the energy efficiency measures.

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[68] Ameren Missouri CaseWorks' Data Request No. UE-DSM_ADJ-01

In his direct testimony, Company witness Steven M. Wills identifies two reasons to true-up the adjustment of the energy efficiency programs' annualizations: 1) more current evaluation, measurement and verification ("EMV") reports for its energy efficiency programs will be available, and 2) a different 12-month time period. Staff agrees that the energy efficiency annualization should be trued-up. Staff will review any true-ups to the adjustment prior to making its true-up recommendation on this issue.

Staff was notified by the Company the week that this Staff Report was due that the dates used to determine the amount of impact for the test year adjustment to usage were the dates the Company sent the incentive checks to participating customers. The Energy Efficiency adjustment should have been calculated from the date each measure was installed. Therefore, the Energy Efficiency Adjustment in this Staff report is greater than it should be. Staff will work with the Company to get the correct timing of the installation of the measures and include this correction in its rebuttal testimony.

Staff Expert/Witness: Hojong Kang

m. Demand-Side Management (DSM) Annualization of Revenues

This adjustment annualizes over the update period the level of kWh reductions resulting from those Ameren Missouri's Energy Efficiency programs in effect at the end of the period. Ameren Missouri converted these annualized kWh reductions to a factor and applied it to each kWh billing determinant of each rate class each month prior to the growth adjustment. Staff witness Hojong Kang confirmed these kWh reductions and provided them to Staff witnesses Curt Wells and Seoung Joun Won, who recalculated the factor based on annualized, normalized kWh (after growth for the weather sensitive classes) and applied rates to arrive at the DSM adjustment.

Staff Experts/Witnesses: Curt Wells and Seoung Joun Won

n. Annualization for the addition of Owensville customers

In March of 2012, Ameren Missouri added customers from the Owensville area to its territory. While this addition occurred outside the update period for this case, a separate adjustment has been included in the cost-of-service calculation to estimate the impact of the additional revenues associated with the Owensville customers. As part of the true-up audit, Staff will examine actual data and will more accurately annualize the revenues associated with the

Owensville customers once more complete billing determinants are available. Staff proposes that the usage and revenue of the Owensville customers be annualized by adjusting and conforming each class' Owensville usage to that of the corresponding Ameren Missouri class' usage as part of its true-up.

Staff Experts/Witnesses: Curt Wells and Roberta A. Grissum

o. Customer Growth Annualization

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additions to, and in certain instances, reductions to kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of January 31, 2012, had existed throughout the entire year. Customer growth was calculated for the Res Non-Time-of-Use, SGS Non-Time-of-Use, LGS Non-Time-of-Use, SPS Non-Time-of-Use, and SPS Time-of-Use customer classes. The customer growth annualization takes into account weather and usage normalizations, as well as the adjustments for 365 days and rate changes that occurred during the test year. Other customer classes that did not exhibit growth were left at test year customer levels instead of being annualized at the January 31, 2012, update period levels. These classes include: Res Time-of-Use, SGS Time-of-Use, SGS Unmetered, LGS Time-of-Use, LPS, Outdoor Lighting, and LTS. The Staff will re-examine the level of customer growth through July 31, 2012, during its true-up audit and make adjustments to the cost of service as necessary.

Staff Expert/Witness: Roberta A. Grissum

p. Annualization and Normalization Results

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

Staff Experts/Witnesses: Curt Wells and Roberta A. Grissum

q. Removal of Rate Refunds

Staff made an adjustment to remove the Provision for Rate Refunds recorded by Ameren Missouri from the test year. This item represents the collections or refunds of prior period revenues related to the Company's FAC and is believed to be an ongoing level. Therefore, this must be eliminated to reflect an accurate revenue requirement for ratemaking purposes.

The Company will appropriately consider these collections or refunds of prior period revenues when it rebases the net base fuel costs in the FAC.

Staff Expert/Witness: Roberta A. Grissum

B. Adjustments to Non-Rate Revenues

1. Lake of the Ozarks Shoreline Management Other Revenues

During the test year, the Company recorded other operating revenues associated with annual fees, certified-dock-builder fees, enforcement fees, and processing fees associated with its Lake of the Ozarks shoreline management activities. Staff examined the level that the Company collected for these fees through April 30, 2012, and noted a significant increase in the level collected by the Company. Staff has reflected an adjustment to decrease the cost-of-service calculation in order to reflect the twelve-months-ending April 30, 2012, level of revenues reported by Ameren Missouri for these four fee categories.

Staff Expert/Witness: John P. Cassidy

2. Storm Assistance Revenues

During the test year the Company received revenue associated with storm assistance that it provided to four other electric utilities. Staff normalized storm assistance revenue based upon a five-year average ending April 30, 2012. This storm assistance revenue adjustment increased the cost-of-service calculation by approximately $1.0 million.

Staff Expert/Witness: John P. Cassidy

3. Coal Refinement Projects

The Cross-State Air Pollution Rule ("CSAPR"), which provides for reductions in emissions of pollutants, such as SO_2, and which was scheduled to take effect on January 1, 2012, has been stayed by the United States Court of Appeals pending judicial review. Should it take effect in the future, Ameren Missouri will need to take steps to either reduce the amount of emissions it produces or will need to obtain emission allowances for its level of emissions. To this end, Ameren Missouri has begun implementation of measures at its Rush Island and Sioux Energy Centers to treat its coal to reduce emissions.

a. Rush Island Energy Center

On December 14, 2011, Ameren Missouri was granted approval by the Commission in Case No. EO-2012-0146 to undertake a coal-refinement process at its Rush Island Energy Center. This process involves Ameren Missouri selling its coal to a third party, Buffington Partners, LLC ("BP"), who applies the refinement process and then in turn sells the refined coal back to Ameren Missouri. The coal-refinement process is designed to reduce emissions of NO_X and SO_2, which are generated from burning coal.

In December of 2011, Ameren Missouri began receiving lease revenues and interest income per its contract with BP. In addition, Ameren Missouri purchased a test run of the treated coal in order to produce fly ash for testing related to its use in concrete. This testing process is not yet completed and approved; therefore, as of April 2012; Ameren Missouri was not utilizing the coal-refinement process at its Rush Island Energy Center. However, it continues to receive lease payments and interest income per its contract agreement with BP. Therefore, Staff has included an annualized ongoing amount in its revenue calculation related to these items. Staff will re-examine this issue as part of its true-up analysis to determine if any changes regarding Ameren Missouri's expenses or revenues have taken place in conjunction with the refinement process at the Rush Island Energy Center.

b. Sioux Energy Center

In addition to Ameren Missouri's coal refinement at the Rush Island Energy Center, a similar project is in the beginning stages at the Sioux Energy Center. Due to the variances in the type of boilers at the Sioux facility, Ameren Missouri has contracted with GS RC Sioux, LLC ("LLC"), to provide refinement of the coal for its Sioux Energy Center based on different technology than that of the Rush Island Energy Center refinement process. Currently, Ameren Missouri has not yet submitted its application to the Commission for approval of the coal-refinement process at the Sioux Energy Center. Staff will reexamine this issue through July 31, 2012, as part of its true-up analysis, to determine if any changes have occurred regarding the refinement process at the Sioux Energy Center.

Staff Expert/Witness: Lisa K. Hanneken

4. Off-System Sales ("OSS")

a. Energy

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

Off-system sales revenues were calculated in the production cost model by using the hourly market energy prices that were determined by Staff witness Erin L. Maloney. Staff's adjustment for off-system sales revenue represents the inclusion of additional revenue in order to annualize the off-system sales revenues that were calculated by Staff witness David W. Elliott using the RealTime® production cost model. This was recorded in the Staff's revenue requirement cost-of-service calculation by subtracting Ameren Missouri's test year ending September 30, 2011, per book off-system sales revenues from Staff's annualized level of off-system sales revenues as determined by the production cost model using Staff's hourly market energy prices.

As part of the Second Nonunanimous Stipulation and Agreement in Case No. ER-2010-0036, the Commission approved the reclassification of the sales-for-resale contracts with AEP and Wabash to off-system sales, as well as the reclassification of contracts with Missouri municipalities. Since Staff's model develops the amount of off-system sales and includes these contracts, Staff has made an adjustment to decrease the off-system revenues resulting from reclassifying these contracts. The Staff will continue to examine off-system sales revenues through July 31, 2012, which represents the true-up cut-off date as approved by the Commission as part of this rate proceeding.

Staff Expert/Witness: Lisa K. Hanneken

b. **Capacity Sales**

When unnecessary to serve its own load, Ameren Missouri is able to sell capacity to other utility companies. Staff also included an adjusted level of capacity sales as part of the cost-of-service calculation in order to reflect actual capacity sales during the twelve months ending April 30, 2012. Staff will re-examine the level of capacity sales as part of its true-up audit.

Staff Expert/Witness: Lisa K. Hanneken

c. **Bilateral Sales and Financial Swaps**

Staff made two additional revenue adjustments outside the production cost model to account for bilateral energy sales margins and financial swaps. The bilateral-energy-sales-margin adjustment is for revenues received by the Company for sales made by the Company to counterparties other than Midwest Independent Transmission System Operator ("MISO") to increase the revenue of underlying generation assets. Staff calculated this adjustment to be approximately $2.6 million based on data as provided per 4 CSR 240-3.190, Reporting Requirements for Electric Utilities and Rural Electric Cooperatives, and information provided per Staff Data Request No. 0397. The financial-swap-revenue adjustment is for financial energy transactions made by the Company to lock-in sales prices of underlying generation assets. Staff made a revenue adjustment of approximately $866,000 to account for these financial swaps based on data provided as per 4 CSR 240-3.190. Staff will continue to review these adjustments through the true-up period ending July 31, 2012, and will update the adjustments as necessary.

Staff Expert/Witness: Erin L. Maloney

5. Midwest Independent Transmission System Operator (MISO)

a. **Day 2 Revenues and Expenses**

Ameren Missouri participates in the MISO activities (often referred to as Day 1 activities prior to April 1, 2005, or "pre-Market") and the MISO day-ahead and real-time energy markets (often called MISO Day 2 or "Midwest Markets"). As part of its participation in the MISO Day 2 markets, during the test year the Company received payments from the MISO related to the Revenue Sufficiency Guarantee ("RSG") provision of MISO's tariff. These payments are designed to ensure that companies participating in the MISO Day 2 markets recover start-up[69] and no-load[70] costs in the event that the market price received does not cover these costs. These two components are the fixed costs of running a generation unit. The market price will always cover the Company's offer price for energy, but in some instances it may not cover the fixed costs of running the unit that are also submitted as a part of Ameren Missouri's offer price. When the Company's total offer prices are not covered by the market prices, Ameren Missouri receives RSG payments.

For Ameren Missouri, the RSG payments received from MISO during the test year totaled $12,131,926. The RSG payments are funded by billings to market participants based on their loads. Thus, Ameren Missouri is billed for RSG payments as a Day 2 market expense and these expenses were included in Staff's revenue requirement cost of service. Both Ameren Missouri's and Staff's models will not dispatch a unit to make sales unless the market price is sufficient to cover start-up and no-load costs. However, these models are based on costs, not offer prices, which may be higher than costs. When the offer price is higher than cost, Ameren Missouri does not require revenue from off-system sales to cover the difference between revenues received from the market prices and revenues required to cover the offer prices. On the other hand, if the RSG payments only make-whole payments that cover only the difference between the cost of running the units and the market price received, then the Staff's production cost model results would be consistent with excluding all RSG payments received from MISO by Ameren Missouri. If the RSG payments only covered cost, then there would be no profit received by Ameren Missouri from actually running a generation unit at times when the production cost model would not dispatch the unit. However, RSG payments cover offer prices made by market participants and those offer prices can include adders to costs. To the extent that Ameren Missouri made offers that are above its costs, the RSG payments more than cover costs, they also include a contribution to profit that is not included in Staff's modeling of net production costs. It is Staff's understanding that offer prices of generation from the Company's gas-fired combustion turbine generators include an adder to cost. Therefore, a portion of the RSG payments related to start-up and no-load costs should be eliminated from test year revenue

[69] Start-up costs are the costs associated with bringing a generation unit on-line.

[70] No-load costs are the costs incurred by a generation unit, after start-up, but prior to providing any output.

because they relate to recovery of the Company's costs, but the portion related to the difference between the costs and offer prices should not be removed as this represents profit that the Company receives from its participation in the MISO Day 2 market. It is important not to exclude this profit, as the Company must make RSG payments to other companies through MISO to not only cover their start-up and no-load costs, but to also cover their offers that include a margin for profits.

Currently, Staff is utilizing a 13% margin rate based on the calculations of margins embedded in the RSG make-whole payments performed during true-up phase in the last case, Case No. ER-2011-0028. In addition, Staff has annualized both test year revenue and expense levels for Day 2 items based on data provided for the 12-months ending April 2012. Staff will re-examine this issue, through July 31, 2012, during its true-up audit.

Staff Expert/Witness: Lisa K. Hanneken

b. Amortization of RSG Resettlement Expenses

Consistent with the Commission's Report and Orders in Case Nos. ER-2008-0318, ER-2010-0036 and ER-2011-0028, relating to MISO resettlement charges, Staff has included an amortization of previously-incurred RSG resettlement expense. However, the amount of Staff's amortization, $272,686 reflects one-half of the $545,372 remaining balance (unamortized portion) of the RSG resettlement cost as of January 2013, the effective date of rates in the current case spread over a 2-year period.

Staff Expert/Witness: Lisa K. Hanneken

c. Transmission Revenue and Expense

Staff is recommending adjustments to the test year level of MISO transmission revenues. These adjustments annualize to a current ongoing level of revenues. The annualization includes changes in revenue distribution and the collection of revenues through Schedule 26, which began June 1, 2011. In addition, the annualization includes Schedule 37 and 38, which began in January 2012 to define charges previously included in Schedule 26. Thus, the test year of 12-months ending September 30, 2011, per books do not reflect a full year of the additional revenues. Staff has annualized the test year's revenue by annualizing data provided for the 12-months ending April 2012, which removes non-recurring expenses and includes a full