MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2016-0285

Jefferson City, Missouri

November 30, 2016

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

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I. Background of KCP&L

Kansas City Power & Light Company ("KCPL") is a Missouri corporation and integrated, regulated electric utility that engages in the generation, transmission, distribution and sale of electricity. KCPL distributes and sells electric service to customers in its certificated areas in western Missouri and eastern Kansas and serves approximately 527,000 customers. KCPL participates in the Southwest Power Pool's ("SPP") integrated market and participates in Federal Energy Regulatory Commission ("FERC") jurisdictional contracts. KCPL is an "electrical corporation" and "public utility" subject to the jurisdiction, supervision, and control of the Missouri Public Service Commission ("the Commission") under Chapters 386 and 393 of the Revised Statues of Missouri. KCPL is wholly-owned by Great Plains Energy Incorporated ("Great Plains" or "GPE") and is an affiliate of KCP&L Greater Missouri Operations Company ("GMO"). KCPL and GMO collectively operate and present themselves to the public under the brand and service mark "KCP&L." Great Plains is a public utility holding company regulated under the Public Utility Holding Company Act of 2005, which was enacted as part of the Energy Policy Act of 2005. Great Plains does not provide electric service to retail customers.

continued on next page

Approximate customer counts for total KCPL (Kansas and Missouri) from 2006 through 2015 follow:

Year	Total	Residential	Commercial	Industrial, Municipal and Other Electric Utilities
2015	527,000	465,200	59,700	2,100
2014	520,700	459,000	59,600	2,100
2013	514,700	453,900	58,700	2,100
2012	511,800	451,500	58,200	2,100
2011	511,000	451,000	58,000	2,100
2010	510,000	450,000	58,000	2,000
2009	509,000	450,000	57,000	2,000
2008	509,000	449,000	58,000	2,000
2007	506,000	446,100	57,600	2,300
2006	505,000	446,000	57,000	2,200

Source: KCPL and Great Plains' 2006-2015 Annual Reports at page 9

Following a 2008 restructuring, KCPL employees perform all the work for Great Plains and its subsidiaries, including GMO. Great Plains and KCPL had 2,899 employees as of December 31, 2015. Of these 2,899 employees, 1,789 employees are represented by three local unions of the International Brotherhood of Electrical Workers ("IBEW"). The local labor unions and when each labor agreement expires are:

Labor Union	Representing	Labor Agreements Expire
Local 1613	Clerical employees	March 31, 2018
Local 1464	Transmission & Distribution Workers	January 31, 2018
Local 412	Power Plant Workers	February 28, 2018

Source: KCPL and Great Plains' 2015 Annual Report at page 9

Staff Expert/Witness: Tammy Huber

II. Executive Summary

On July 1, 2016, KCPL applied to increase revenues, before impacts of the rebasing of fuel for the Fuel Adjustment Clause (FAC), $62.9 million or 7.52% for KCPL Missouri jurisdiction. The aggregate annual increase over current revenues that the tariffs proposed, including the rebasing of fuel for the FAC, is $90.1 million or 10.77% for KCPL.[1] KCPL

[1] Direct Testimony of Darrin R. Ives, page 5.

proposed a return on equity ("ROE") of 9.90%. If granted, this revenue requirement would produce an approximate 7.52% increase to each customer class. This increase is over the current revenues of $836.5 million. Also in its Direct Filing, KCPL proposed to continue reflecting approved fuel and purchased power increases and decreases in the FAC. The fuel and purchased power is rebased in each general rate request, resulting in an additional 3.3% increase in base rates in this case.

Staff reviewed all cost-of-service components (capital structure, return on rate base, rate base, depreciation expense and operating expenses) that comprise KCPL's revenue requirement.

Based on the information available at the time of filing Staff's Cost of Service Report, Staff does not have enough information to support a change in rates. If the Commission determines new rates are appropriate, Staff recommends a ROE of 8.65%, which is on the upper end of the equity cost rate range of 7.9% to 8.75%. Combined with recommended capitalization ratios and senior capital cost rate, overall rate of return cost of capital for KCPL is 7.01%.

Below are definitions of technical terms that will frequently be used in the Cost of Service Report:

Test Year: The test year income statement is the starting point for determining a utility's existing annual revenues, operating costs, and net operating income. In this case, the test year is the 12 months ending December 31, 2015.

Update Period: The standard practice in ratemaking in Missouri to utilize a period, beyond the established test year for a case, in which to match the major components of a utility's revenue requirement. The update period that was agreed to for this particular case is the 12 months ending June 30, 2016.

True-Up: A true-up date generally is established when a significant change in a utility's cost of service occurs after the end of the update period, but prior to the operation-of-law date, and one or more of the parties has decided this significant change in cost of service should be considered for cost-of-service recognition in the current case. True-up audits involve the filing of additional testimony and, if necessary, additional hearings beyond the initial testimony filings and hearings for a case. The true-update ordered in this case is December 31, 2016.

Normalization: Utility rates are intended to reflect normal ongoing operations. A normalization adjustment is required when the test year reflects the impact of an abnormal event. For example, overtime expense may be normalized to remove an unusual weather event, and revenue may be normalized to remove abnormal weather conditions.

Annualization: Annualization adjustments are the most common adjustment made to test year results to reflect the utility's most current annual level of revenue and expenses. Annualization adjustments are required when changes have occurred during the test year and/or update period, which are not fully reflected in the unadjusted test year results. For example, signing a new labor contract would necessitate annualizing the new level of wages to expense. Similarly, an addition of a large industrial customer would necessitate an annualization of billing determinants and revenues.

Disallowances: In examining test year results, Staff makes disallowances to costs that should not be recovered in rates. Examples of these types of costs are certain advertising costs and donations made to charitable organizations.

Return on Equity: The ROE is the return allowed in rates on the shareholders' equity investment in a regulated utility.

Rate of Return: The ROR is the overall cost capital; that is, the cost of debt and the Commission-selected ROE weighted by the capital structure.

Short forms used in the Staff's Revenue Requirement Report and Class Cost-of-Service Report include:

"the Commission" for the Missouri Public Service Commission;

"Staff" for the Staff of the Missouri Public Service Commission;

"KCPL" for Kansas City Power & Light Company;

"GMO" for KCP&L Greater Missouri Operations Company;

"Public Counsel" for the Office of the Public Counsel;

"EMS" for Staff's revenue requirement model referred to as Exhibit Modeling System;

"ROE" for Return on Equity;

"ROR" for Rate of Return;

"SPP" for Southwest Power Pool;

"RTO" for Regional Transmission Organization

Staff Expert/Witness: Tammy Huber

III. Economic Considerations

The indicators of Missouri's general economic condition, specifically of the Missouri counties[2] that compose the service area of KCPL, indicate that moderate growth continues. Figure 1 below shows that the real gross domestic product ("GDP") growth of Missouri has averaged less than one percent (1%) per year from 2010 to 2015. Preliminary 2015 data had shown a robust year-over-year growth rate at 2.80 percent, but subsequent revisions lowered the growth to only 1.29 percent.

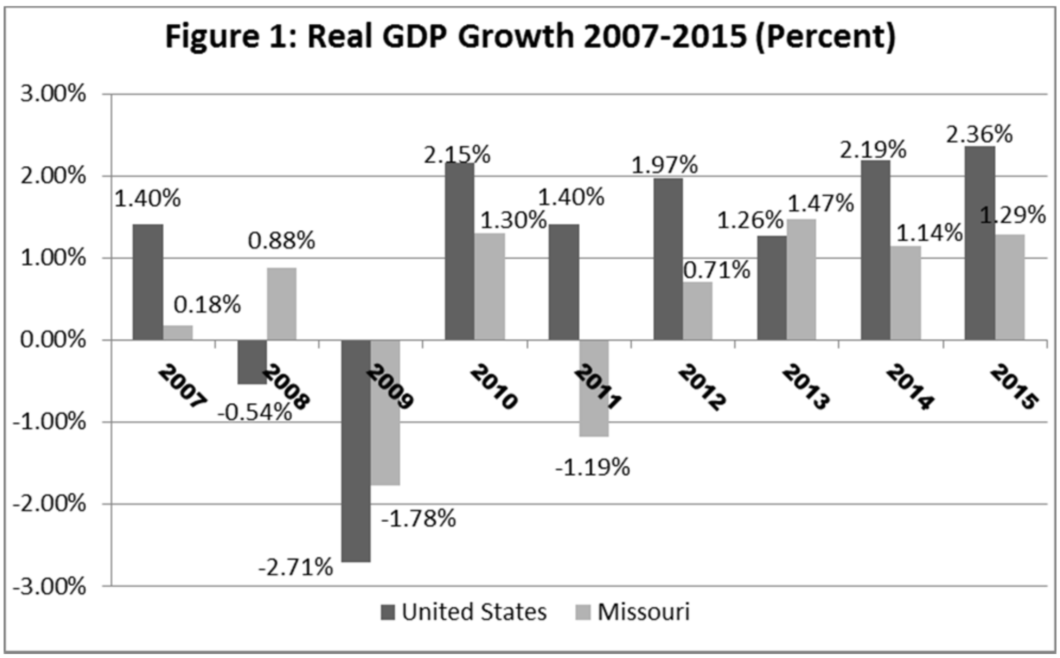

Figure 1: Real GDP Growth 2007-2015 (Percent)

Despite a low GDP growth rate, Figure 2 shows that the annual unemployment rate levels for Missouri, including the preliminary 2016 levels, are below the pre-recession levels, but the unemployment rate for the U.S. rate has yet to reach the pre-recession lows.[3] The combined unemployment rate for all of the Missouri counties that KCPL serves tends to be 0.2 to 0.3 percent above Missouri's overall unemployment rate.[4]

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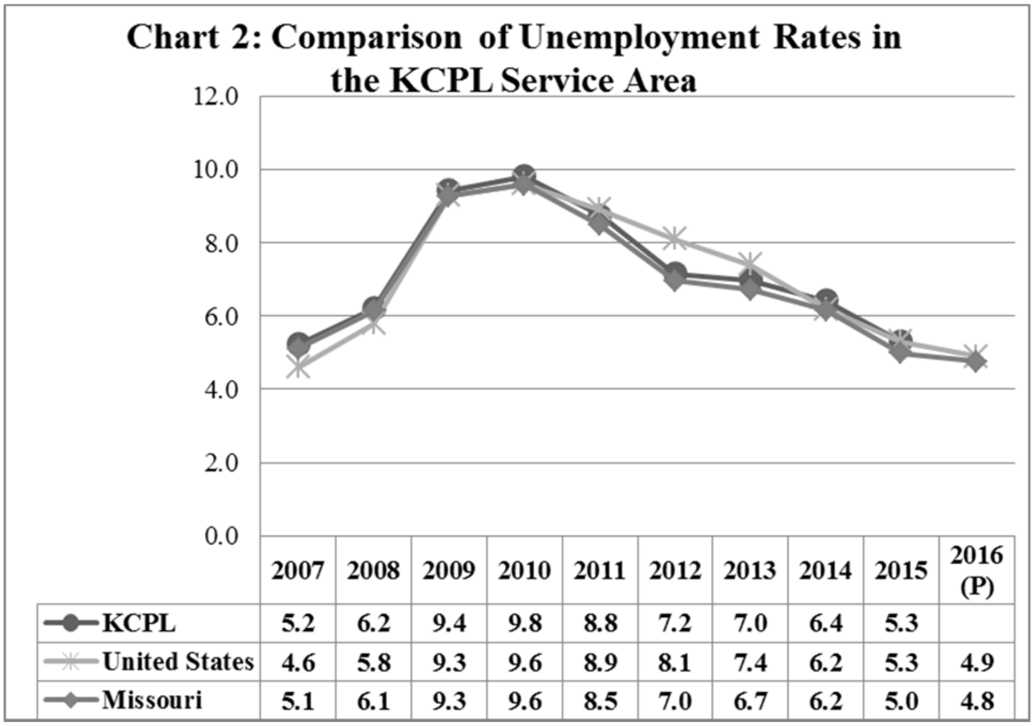
[2] According to Appendix 3 of KCPL's application, which includes the minimum filing requirements, and KCPL's current tariff, KCPL serves a total of 13 counties.

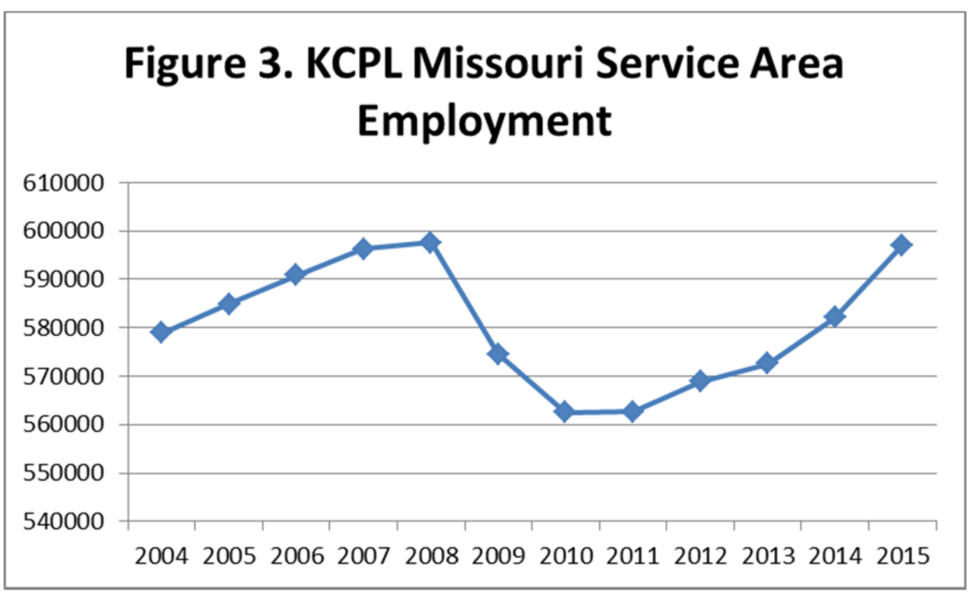
[3] According to the National Bureau of Economic Research, the recession began in December 2007 and ended in June 2009.

[4] The county level unemployment data is unavailable for 2016.



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016 (P)
KCPL	5.2	6.2	9.4	9.8	8.8	7.2	7.0	6.4	5.3	
United States	4.6	5.8	9.3	9.6	8.9	8.1	7.4	6.2	5.3	4.9
Missouri	5.1	6.1	9.3	9.6	8.5	7.0	6.7	6.2	5.0	4.8

Some economists have expressed concern that the unemployment rate statistic has not accurately reflected a lower labor-force participation rate. Figure 3 shows the number of employed persons in KCPL's Missouri service area is near the pre-recession peak. While not correcting for population growth, Figures 2 and 3 together show that the employment situation in Missouri continues to improve.



In addition to examining the status of the current economy, economic forecasters also examine economic data that have a history of leading, lagging, or coinciding with changes in the broader economy to anticipate future economic conditions. The current economic outlook from a variety of economic forecasters has been cautious. For instance, the American Institute for Economic Research's ("AIER")[5] most recent version of Business Cycle Conditions (November 2016) shows that 58 percent of the leading indicators are evaluated as expanding.[6] Under AIER's method, consistent evaluations above 50 percent suggest a low probability of recession over the next six to 12 months. This was the second month that was evaluated above 50 percent after six months in a row where the evaluation was at or below 50 percent. AIER states, "[W]e do not believe there is enough evidence to suggest the economy is on a significantly different path. Consequently, we still believe the results over the past nine months are consistent with overall slow growth and continued economic expansion."[7]

Figure 4, below, provides a comparison of the increase in average weekly wages for the counties in the Missouri KCPL service area, Consumer Price Index ("CPI"), Producer Price Index ("PPI"),[8] and KCPL's electric rates. From 2007 to 2015, the Missouri counties in the KCPL service area collectively experienced a 17.62% increase in average weekly wages. This was slightly lower than the overall Missouri compounded increase in average weekly wages of 18.03% and about 3% above the CPI increase. During that same time period, KCPL filed six rate cases[9] which increased overall electric rates for customers served by KCPL by approximately $283.1 million, or a cumulative total of 57.69%, as shown in Table 1. However, KCPL has also experienced inflationary pressure, illustrated by a 10.31% increase in the PPI for Industrial

[5] American Institute for Economic Research. (09NOV16). "Business Conditions Monthly." https://www.aier.org/sites/default/files/Documents/Research/pdf/BCM_November2016.pdf (15NOV16).

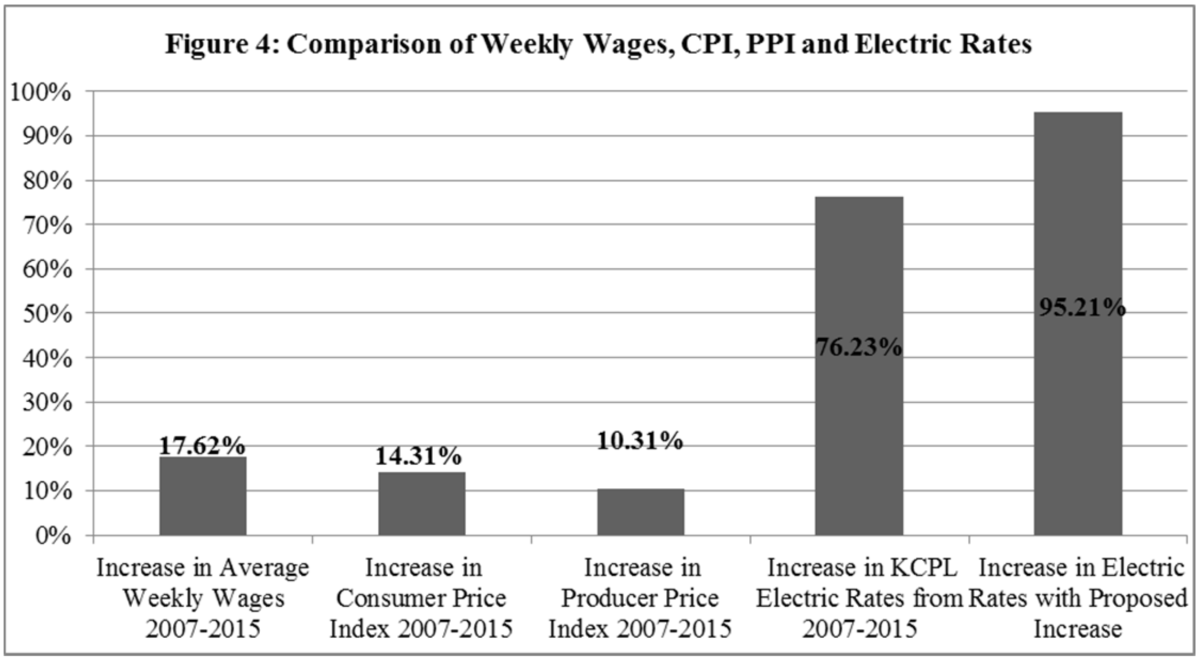
[6] AIER uses 24 indicators in total – 12 leading indicators are a measurable economic factor that tend to change ahead of a turning point in the broader economy, six coincident indicators that tend to change at roughly the same time as a change in the broader economy, and six lagging indicators that tend to change after a turning point in the broader economy. AIER recently revised its list of indicators, details of which can be found at https://www.aier.org/revising. A leading indicator evaluated as expanding means that the change in that indicator is historically correlated with future economic growth.

[7] American Institute for Economic Research. (09NOV16). "Business Conditions Monthly." https://www.aier.org/sites/default/files/Documents/Research/pdf/BCM_November2016.pdf (15NOV16).

[8] 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.

[9] Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355, ER-2012-0174, and ER-2014-0370.

Commodities from 2007 to 2015.[10] KCPL is currently requesting an additional $90.1 million—a 10.77% increase in permanent rates.[11] From 2007 to 2015, the increase in average weekly wages for Missouri counties in the KCPL service area is about one-fourth of the increase in electric rates for KCPL customers. If KCPL receives its requested 10.77% increase, the increase in average weekly wages would be less than one-fifth of the increase in electric rates, but this does not include any increase in average weekly wages for 2016, which is currently unavailable.



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[10] Detailed information on KCPL's expenditures and revenues can be found later in this report.

[11] Since some of the proposed increase in permanent rates is currently collected in the fuel adjustment clause, the apparent proposed increase on customers is approximately $62.9 million or 7.52%.

Table 1: KCPL Rate Case History 2007 - 2016			
Case Number	Effective Date	Dollar Value	Percent Increase
ER-2006-0314	1-Jan-07	$50,616,638	10.46%
ER-2007-0291	1-Jan-08	$35,308,914	6.50%
ER-2009-0089	1-Sep-09	$95,000,000	16.16%
ER-2010-0355	4-May-11	$34,817,199	5.25%
ER-2012-0174	26-Jan-13	$67,390,893	9.64%
ER-2014-0370	29-Sep-15	$89,671,644	11.76%
Total Dollars		$372,805,288	
Total Compounded Increase			76.23%
ER-2016-0285	(Proposed)	$90,076,613	10.77%
Total with Proposed		*$462,881,901*	*95.21%*

Staff Expert/Witness: Michael L. Stahlman

IV. Rate of Return

A. Overview

An essential ingredient of the cost-of-service ratemaking formula is the ROR, which is usually premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. A company's overall ROR consists of three main categories: (1) capital structure (i.e., ratios of short-term debt, long-term debt, preferred stock and common equity); (2) cost rates for short-term debt, long-term debt, and preferred stock; and (3) common equity cost, which in utility ratemaking is often considered synonymous with the ROE even if they aren't in equilibrium.

A ROE is most simply described as the allowed rate of profit for a regulated company. In a competitive market, a company's profit level is determined by a variety of factors, including the state of the economy, the degree of competition a company faces, the ease of entry into its markets, the existence of substitute or complementary products/services, the company's cost structure, the impact of technological changes, and the supply and demand for its services and/or products. For a regulated monopoly, the regulator determines the level of profit potentially available to the utility. The United States Supreme Court established the guiding principles for establishing an appropriate level of profitability for regulated public utilities in two cases: (1) *Bluefield* and (2) *Hope*.[12] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Thus, the appropriate allowed ROE for a regulated utility requires estimating the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. The purpose of all of the economic models and formulas in cost of capital testimony (including those presented later in my testimony) is to estimate, using market data of similar-risk firms, the rate of return equity investors require for that risk-class of firms in order to set an appropriate ROE for a regulated firm.

This report provides an overall fair ROR or cost of capital recommendation for the regulated electric utility operations of KCPL and evaluates KCPL ROR testimony in this proceeding.

This report is organized as follows: (1) a review of Staff's cost of equity estimate for KCPL, (2) an assessment of capital costs in today's capital markets; (3) selection of a proxy group of electric utility companies for estimating the market cost of equity for KCPL; (4) a discussion of the capital structure of KCPL; and (5) an overview of the concept of cost of equity capital and an estimate of the equity cost rate for KCPL.

B. Summary of Positions

KCPL has proposed a capital structure of 50.12% long-term debt and 49.88% common equity based on KCPL's projected capital structure as of December 31, 2016. KCPL recommended a long-term debt cost rate of 5.51%. KCPL witness Mr. Robert B. Hevert has

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[12] *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*") and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

recommended a ROE of 9.90% for the electric utility operations of KCPL. KCPL's overall proposed ROR is 7.70%.

I have reviewed KCPL's proposed capital structure and embedded costs of capital. From discussions with internal Staff and review of past testimonies and reports in both KCPL and GMO rate cases, it is my understanding that in past rate cases Staff and KCPL had recommended the use of GPE's consolidated capital structure to set rates for both KCPL and GMO. As of June 30, 2016, this capital structure includes 50.41% long-term debt, 0.52% preferred stock, and 49.07% common equity. I have adjusted these amounts since the Company redeemed the preferred stock in August. As a result, I am recommending a capital structure of 50.8% long-term debt and 49.2% common equity. I have also adjusted KCPL's cost of debt because the Company has used a blending of the yield-to-maturity and simple interest/amortization methods. My adjusted cost of debt is 5.42%.

The use of GPE's capital structure and cost of debt as compared to KCPL's, results in a revenue requirement that is about $1 million lower. Because GPE has managed its utility finances on a consolidated basis and KCPL's cost of debt is higher than its weaker affiliate, GMO, it is fair to continue the use of GPE's consolidated capital structure and capital costs for setting KCPL's rates. However, the primary difference in my recommended rate of return and KCPL's is our common equity cost estimates.

To estimate an equity cost rate for KCPL, I have applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to my proxy group of electric utilities ("Electric Proxy Group"). I have also used Mr. Hevert's proxy group ("Hevert Proxy Group") for purposes of comparison to my Electric Proxy Group analysis. Mr. Hevert has also employed an alternative risk premium ("RP") approach, which he calls the Bond Yield Plus Risk Premium approach. My recommendation is that the appropriate ROE for KCPL is 8.65%. This figure is at the upper end of my equity cost rate range of 7.9% to 8.75%. Combined with my recommended capitalization ratios and senior capital cost rate, my overall rate of return or cost of capital for KCPL is 7.01% as summarized in Exhibit JRW-1.

My equity cost rate recommendation is consistent with the current economic environment. Despite dire and unfounded predictions of rising interest rates over the past several years, long-term interest rates and capital costs are still at historic lows. As I discuss below, there are strong indicators from my assessment study of global capital markets that long term capital costs will remain low. In estimating a common equity cost rate I have applied the DCF and the CAPM approaches to proxy groups of publicly-held electric utility companies that include the same proxy group used by Mr. Hevert.

I review current market conditions and conclude that interest rates and capital costs are at historically low levels and are likely to remain low for some time. On this issue, I show that the economists' forecasts of higher interest rates and capital costs have been consistently wrong for a decade.

I have employed the traditional constant-growth DCF model. When developing the DCF growth rate that I have used in my analysis, I have reviewed thirteen growth rate measures including historical and projected growth rate measures and have evaluated growth in dividends, book value, and earnings per share.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the market or risk premium. As I highlight in my testimony, there are three methods for estimating a market or equity risk premium – historical returns, surveys, and expected return models. I have used a market risk premium of 5.5%, which: (1) employs three different approaches to estimating a market premium; and (2) uses the results of many studies of the market risk premium. As I note, my market risk premium reflects the market risk premiums: (1) determined in recent academic studies by leading finance scholars; (2) employed by leading investment banks and management consulting firms; and (3) found in surveys of companies, financial forecasters, financial analysts, and corporate CFOs.

C. Capital Costs In Today's Markets

1. <u>Historic Interest Rates and Capital Costs</u>

Long-term capital cost rates for U.S. corporations are a function of the required returns on risk-free securities plus a risk premium. The risk-free rate of interest is the yield on long-term U.S. Treasury bonds. The yields on 10-year U.S. Treasury bonds from 1953 to the present are provided on Panel A of Exhibit JRW-2. These yields peaked in the early 1980s and have generally declined since that time. These yields fell to below 3.0% in 2008 as a result of the financial crisis. In 2012, the yields on 10-year Treasuries declined from 2.5% to 1.5% as the Federal Reserve initiated the third stage of its quantitative easing program ("QEIII") to support a low interest rate environment. These yields increased to 3.0% as of December of 2013 on speculation of a tapering of the Federal Reserve's QEIII policy. Since that time, the Federal Reserve has ended the QEIII program and has increased the federal funds rate. Nonetheless, due to slow economic growth and low inflation, the 10-year Treasury yield declined and bottomed out at 1.5% range as of mid-2016. They have since increased to 2.25%, with the majority of that increase coming in response to the U.S. presidential election.

Panel B on Exhibit JRW-2 shows the differences in yields between 10-year Treasuries and Moody's Baa-rated bonds since the year 2000. This differential primarily reflects the additional risk premium required by bond investors for the risk associated with investing in corporate bonds as opposed to obligations of the U.S. Treasury. The difference also reflects, to some degree, yield curve changes over time. The Baa rating is the lowest of the investment grade bond ratings for corporate bonds. The yield differential hovered in the 2.0% to 3.5% range until 2005, declined to 1.5% until late 2007, and then increased significantly in response to the financial crisis. This differential peaked at 6.0% at the height of the financial crisis in early 2009 due to tightening in credit markets, which increased corporate bond yields, and the "flight to quality," which decreased Treasury yields. The differential subsequently declined and bottomed out at 2.4%. The differential has since increased to the 3.25% range.

The risk premium is the return premium required by investors to purchase riskier securities. The risk premium required by investors to buy corporate bonds is observable based on yield differentials in the markets. The market risk premium is the return premium required to purchase stocks as opposed to bonds. The market or equity risk premium is not readily observable in the markets (like bond risk premiums) since expected stock market returns are not readily observable. As a result, equity risk premiums must be estimated using market data. There are alternative methodologies to estimate the equity risk premium, and these alternative approaches and equity risk premium results are subject to much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5% to 7% range.[13] However, studies by leading academics indicate that the forward-looking equity risk premium is actually in the 4.0% to 6.0% range. These lower equity risk premium results are in line with the findings of equity risk premium surveys of CFOs, academics, analysts, companies, and financial forecasters.

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[13] *See* Exhibit JRW-11, p. 5-6.

Panel A of Exhibit JRW-3 provides the yields on A-rated public utility bonds. These yields peaked in November 2008 at 7.75% and henceforth declined significantly. These yields declined to below 4.0% in mid-2013, and then increased with interest rates in general to the 4.85% range as of late 2013. These rates dropped significantly during 2014 due to economic growth concerns and bottomed out below 4.0% in the first quarter of 2015. They increased with interest rates in general to 4.4% in the summer of 2015, and have since declined to the 4.0% range due to continued low economic growth and inflation.

Panel B of Exhibit JRW-3 provides the yield spreads between long-term A-rated public utility bonds relative to the yields on 20-year U.S. Treasury bonds. These yield spreads increased dramatically in the third quarter of 2008 during the peak of the financial crisis and have decreased significantly since that time. The yield spreads between 20-year U.S. Treasury bonds and A-rated utility bonds peaked at 3.4% in November 2008, declined to about 1.5% in the summer of 2012 as investor return requirements declined. The differential has gradually increased in recent years, and is now close to 2.0%.

2. Current Capital Market Conditions

a. Forecasts of Higher Interest Rates

As discussed above, a company's ROR is theoretically supposed to be approximately equal to its overall cost of capital in the long run. Capital costs, including the cost of debt and equity financing, are established in capital markets and reflect investors' return requirements on alternative investments based on risk and capital market conditions. These capital market conditions are a function of investors' expectations concerning many factors, including economic growth, inflation, government monetary and fiscal policies, and international developments, among others. In the wake of the financial crisis, much of the focus in the capital markets has been on the interaction of economic growth, interest rates, and the actions of the Federal Reserve (the "Fed"). In addition, as illustrated in the United Kingdom's June 24th referendum to leave the European Union ("BREXIT"), capital markets are global and capital costs are impacted by global events.

In the last couple of years, with the end of the Fed's QEIII program as well as in anticipation of the Fed's December 16, 2015, decision to raise the Federal Funds rate, there have been forecasts of higher long-term interest rates. However, these forecasts have proven to be wrong. For example, after the announcement of the end of the QEIII program, all the economists in Bloomberg's interest rate survey forecasted interest rates would increase in 2014, and 100% of the economists were wrong. According to the *Market Watch* article:[14]

> The survey of economists' yield projections is generally skewed toward rising rates — only a few times since early 2009 have a majority of respondents to the Bloomberg survey thought rates would fall. But the unanimity of the rising rate forecasts in the spring was a stark reminder of how one-sided market views can become. It also teaches us that economists can be universally wrong.

Two other financial publications have produced studies on how economists consistently predict higher interest rates yet they have been wrong. The first publication, entitled "How Interest Rates Keep Making People on Wall Street Look Like Fools," evaluated economists' forecasts for the yield on ten-year Treasury bonds at the beginning of the year for the last ten years.[15] The results demonstrated that economists consistently predict that interest rates will increase, but they never do.

The second study tracked economists' forecasts for the yield on ten-year Treasury bonds on an ongoing basis from 2010 until 2015.[16] The results of this study, which was entitled "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," are shown in Figure 1 and demonstrate how economists continually forecast that interest rates are going up, and they do not. Indeed, as Bloomberg has reported, economists' continued failure in forecasting increasing interest rates has caused the Federal Reserve Bank of New York to stop using the interest rate estimates of professional forecasters in the Bank's interest rate model due to the unreliability of those forecasters' interest rate forecasts.[17]

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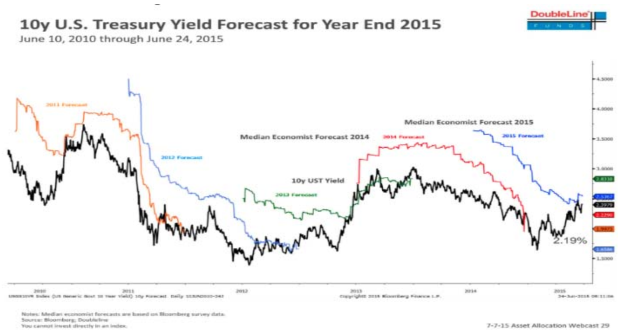
14 Ben Eisen, "Yes, 100% of economists were dead wrong about yields, *Market Watch*," October 22, 2014**.** Perhaps reflecting this fact, *Bloomberg* reported that the Federal Reserve Bank of New York has stopped using the interest rate estimates of professional forecasters in the Bank's interest rate model due to the unreliability of those forecasters' interest rate forecasts. See Susanne Walker and Liz Capo McCormick, "Unstoppable $100 Trillion Bond Market Renders Models Useless," *Bloomberg.com* (June 2, 2014). http://www.bloomberg.com/news/2014-06-01/the-unstoppable-100-trillion-bond-market-renders-models-useless html.

15 Joe Weisenthal, "How Interest Rates Keep Making People on Wall Street Look Like Fools," Bloomberg.com, March 16, 2015. http://www.bloomberg.com/news/articles/2015-03-16/how-interest-rates-keep-making-people-on-wall-street-look-like-fools.

16 Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time-2015-7.

17 *Market Watch*," October 22, 2014.

Figure 1
Economists' Forecasts of the Ten-Year Treasury Yield
2010-2015



Source: Akin Oyedele, "Interest Rate Forecasters are Shockingly Wrong Almost All of the Time," *Business Insider*, July 18, 2015. http://www.businessinsider.com/interest-rate-forecasts-are-wrong-most-of-the-time.

b. The Federal Reserve's Decision to Increase the Federal Funds Rate

The Federal funds rate is set by the Fed and is the borrowing rate applicable to the most creditworthy financial institutions when they borrow and lend funds overnight to each other.[18] On December 16, 2015, the Fed decided to increase the target rate for Federal Funds to ¼ - ½ percent. In the release, the Federal Open Market Committee ("FOMC") included the following observations:[19] The increase came after the rate was kept in the 0.0 to 0.25 percent range for over five years in order to spur economic growth in the wake of the financial crisis. The move followed by almost two years the end of QEIII program, the Fed's bond-buying program. The Fed has been cautious in its approach to scaling its monetary intervention, and has paid close attention to a number of economic variables, including GDP growth, retail sales, consumer confidence, unemployment, the housing market, and inflation. While the Fed has cited improvements in many areas of the economy, it has expressed concern with the low inflation rate – below the Fed's target of 2.0%.

Nonetheless, it is widely accepted that the Fed will raise the federal funds rate in December of this year. This does not necessarily mean the long-term interest rates are going up. As noted, the federal funds rate is an overnight rate, not a long-term interest rate. In fact, after the Fed increased the federal funds rate last December, long term interest rates declined. The yield on 30-year Treasury bonds was about 3.0% at the time of the decision, declined to below

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[18] http://www.investopedia.com/terms/f/federalfundsrate.asp
[19] Board of Governors of the Federal Reserve System, *FOMC Statement* (Dec. 16, 2015).

2.50% in 2016, and has now increased back to the 3.0% range in the wake of the U.S. presidential election.

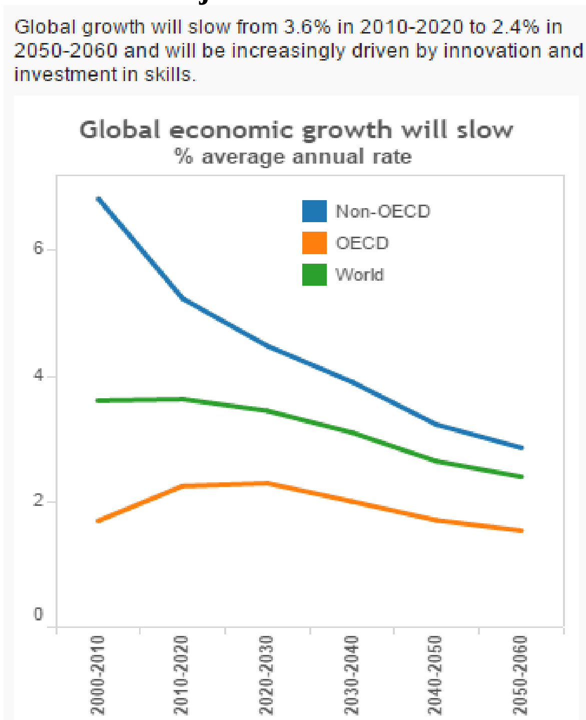
c. Interest Rates and Capital Costs in the Long Run

In the long run, the key drivers of economic growth measured in nominal dollars are population growth, the advancement and diffusion of science and technology, and currency inflation. Although we experienced rapid economic growth during the "post-war" period (the 63 years that separated the end of World War II and the 2008 financial crisis), the post-war period is not necessarily reflective of expected future growth. It was marked by a near-tripling of global population, from under 2.5 billion to approximately 6.7 billion. Over the next 54 years, according to U.N. projections, the global population will grow considerably more slowly, reaching approximately 10.3 billion in 2070. With population growth slowing, life expectancies lengthening, and post-war "baby boomers" reaching retirement age, median ages in developed-economy nations have risen and continue to rise. The postwar period was also marked by rapid catch-up growth as Europe, Japan, and China recovered from successive devastations and as regions such as India and China deployed and leapfrogged technologies that had been developed over a much longer period in earlier-industrialized nations. That period of rapid catch-up growth is coming to an end. For example, although China remains one of the world's fastest-growing regions, its growth is now widely expected to slow substantially. This convergence of projected growth in the former "second world" and "third world" towards the slower growth of the nations that have long been considered "first world" is illustrated in this "key findings" chart published by the Organization for Economic Co-operation and Development:[20]

continued on next page

[20] See http://www.oecd.org/eco/outlook/lookingto2060.htm.

Figure 2
Projected Global Growth



As to dollar inflation, it has declined to far below the level it reached in the 1970s. The Fed targets a 2% inflation rate, but inflation has been below this figure. Indeed, inflation has been below the Fed's target rate for over three years due to a number of factors, including slow global economic growth, slack in the economy, and declining energy and commodity prices. The slow pace of inflation is also reflected in the decline in forecasts of future inflation. The Energy Information Administration's annual Energy Outlook includes in its nominal GDP growth projection a long-term inflation component, which the EIA projects at only 2.1% per year for its forecast period through 2040.[21]

All of this translates into slowed growth in annual economic production and income, even when measured in nominal rather than real dollars. Meanwhile, the stored wealth that is available to fund investments has continued to rise. According to the most recent release of the Credit Suisse global wealth report, global wealth has more than doubled since the turn of this century, notwithstanding the temporary setback following the 2008 financial crisis:

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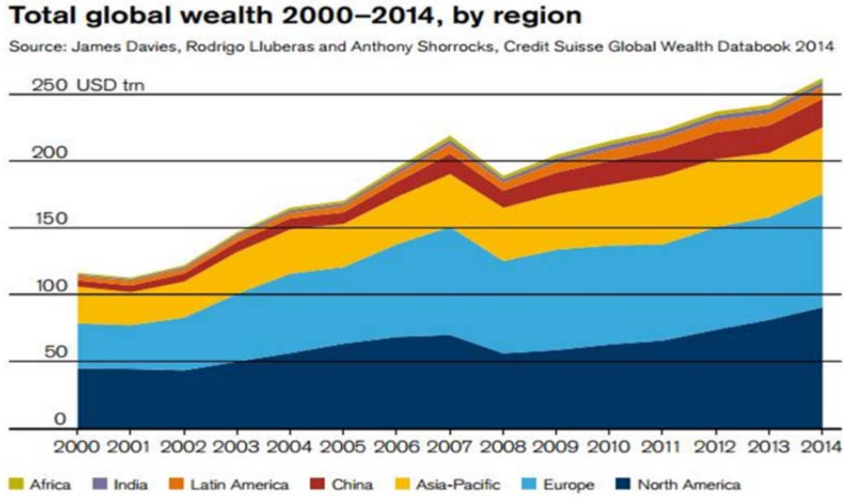
[21] See EIA Annual Energy Outlook 2016, Table 20 (available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm).

Figure 3
Global Wealth – 2000-2014



These long-term trends mean that overall, and relative to what had been the post-war norm, the world now has more wealth chasing fewer opportunities for investment rewards. Ben Bernanke, the former Chairman of the Federal Reserve, called this phenomenon a "global savings glut."[22] Like any other liquid market, capital markets are subject to the law of supply and demand. With a large supply of capital available for investment and relatively scarce demand for investment capital, it should be no surprise to see the cost of investment capital decline and therefore interest rates should remain low.

Former the Fed Chairman Ben Bernanke addressed the issue of the continuing low interest rates in his weekly Brookings Blog. Bernanke indicated that the focus should be on real and not nominal interest rates and noted that, in the long term, these rates are not determined by the Fed:[23]

> If you asked the person in the street, "Why are interest rates so low?," he or she would likely answer that the Fed is keeping them low. That's true only in a very narrow sense. The Fed does, of course, set the benchmark nominal short-term interest rate. The Fed's policies are also the primary determinant of inflation and inflation expectations over the longer term, and inflation trends affect interest rates, as the figure above shows. But what matters most for the economy is the real, or inflation-adjusted, interest rate (the market, or nominal, interest rate minus the inflation rate). The

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[22] Ben S. Bernanke, *The Global Saving Glut and the U.S. Current Account Deficit* (Mar. 10, 2005), available at http://www federalreserve.gov/boarddocs/speeches/2005/200503102/.

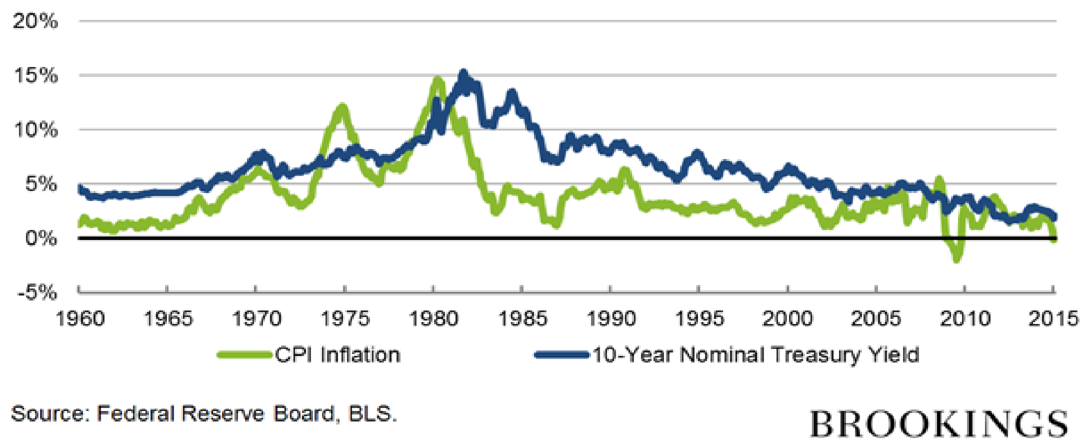
[23] Ben S. Bernanke, "Why Are Interest Rates So Low," Weekly Blog, Brookings, March 30, 2015. http://www.brookings.edu/blogs/ben-bernanke/posts/2015/03/30-why-interest-rates-so-low.

> real interest rate is most relevant for capital investment decisions, for example. The Fed's ability to affect real rates of return, especially longer-term real rates, is transitory and limited. Except in the short run, real interest rates are determined by a wide range of economic factors, including prospects for economic growth—not by the Fed.

Bernanke also addressed the issue about whether low-interest rates are a short-term aberration or a long-term trend:[24]

> Low interest rates are not a short-term aberration, but part of a long-term trend. As the figure below shows, ten-year government bond yields in the United States were relatively low in the 1960s, rose to a peak above 15 percent in 1981, and have been declining ever since. That pattern is partly explained by the rise and fall of inflation, also shown in the figure. All else equal, investors demand higher yields when inflation is high to compensate them for the declining purchasing power of the dollars with which they expect to be repaid. But yields on inflation-protected bonds are also very low today; the real or inflation-adjusted return on lending to the U.S. government for five years is currently about minus 0.1 percent.

Figure 4
Interest Rates and Inflation
1960-Present



d. Summary Observations on Current Capital Market Conditions

I believe that U.S. Treasuries offer an attractive yield relative to those of other major governments around the world, which will attract capital to the U.S. and keep U.S. interest rates down. There are several factors driving this conclusion.

[24] Ibid.

First, the economy has been growing for over five years, and, as noted above, the Fed sees continuing strength in the economy. The labor market has improved, with unemployment now 5.0%.[25]

Second, interest rates remain at historically low levels and are likely to remain low. There are two factors driving the continued lower interest rates: (1) inflationary expectations in the U.S. remain low and remain below the FOMC's target of 2.0%; and (2) global economic growth – including Europe where growth is stagnant and China where growth is slowing significantly. As a result, while the yields on long-term U.S. Treasury bonds are low by historical standards, these yields are well above the government bond yields in Germany, Japan, and the United Kingdom. Thus, U.S. Treasuries offer an attractive yield relative to those of other major governments around the world, thereby attracting capital to the U.S. and keeping U.S. interest rates down.

Given these observations, I suggest that the Commission set an equity cost rate based on current market cost rate indicators and not speculate on the future direction of interest rates. As the above studies indicate, economists are always predicting that interest rates are going up, and yet they are almost always wrong. Obviously, investors are well aware of the consistently wrong forecasts of higher interest rates, and therefore place little weight on such forecasts. Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns. For example, consider a utility that pays a dividend of $2.00 with a stock price of $50.00. The current dividend yield is 4.0%. If interest rates and required utility yields increase, the price of the utility stock would decline. In the example above, if higher return requirements led the dividend yield to increase from 4.0% to 5.0% in the next year, the stock price would have to decline to $40, which would be a -20% return on the stock.[26] Obviously, investors would not buy the utility stock with an expected return of -20% due to higher dividend yield requirements.

In sum, forecasting prices and rates that are determined in the financial markets, such as interest rates, the stock market, and gold prices, appears to be impossible to accurately do. For interest rates, I have never seen a study that suggests one forecasting service is consistently better than others or that interest rate forecasts are consistently better than just assuming that the

[25] See http://data.bls.gov/timeseries/LNS14000000.

[26] In this example, for a stock with a $2.00 dividend, a dividend yield 5.0% dividend yield would require a stock price of $40 ($2.00/$40 = 5.0%).

current interest rate will be the rate in the future. As discussed above, investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns.

D. Proxy Group Selection

To develop a fair rate of return recommendation for the Company, I have evaluated the return requirements of investors on the common stock of a proxy group of publicly-held utility companies. The selection criteria for the Electric Proxy Group include the following:

1. At least 50% of revenues from regulated electric operations as reported by *AUS Utilities Report*;
2. Listed as an Electric Utility by *Value Line Investment Survey* and listed as an Electric Utility or Combination Electric & Gas Utility in *AUS Utilities Report*;
3. An investment grade issuer credit rating by Moody's and Standard & Poor's ("S&P");
4. Has paid a cash dividend in the past six months, with no cuts or omissions;
5. Not involved in an acquisition of another utility, the target of an acquisition, or in the sale or spin-off of utility assets, in the past six months; and
6. Analysts' long-term earnings per share ("EPS") growth rate forecasts available from Yahoo, Reuters, and/or Zacks.

The Electric Proxy Group includes thirty companies. Summary financial statistics for the proxy group are listed in Panel A of page 1 of Exhibit JRW-4.[27] The median operating revenues and net plant among members of the Electric Proxy Group are $6,084.5 million and $16,741.0 million, respectively. The group receives 81% of its revenues from regulated electric operations, has BBB+/Baa1 issuer credit ratings from S&P and Moody's respectively, a current common equity ratio of 47.1%, and an earned return on common equity of 9.1%.

In addition to this group, I have also employed Mr. Hevert's Proxy Group. The Hevert Proxy Group consists of sixteen companies.[28] Summary financial statistics for the proxy group are listed on Panel B of page 1 of Exhibit JRW-4. The median operating revenues and net plant among members of the Hevert Proxy Group are $2,694.4 million and $8,658.2 million, respectively. The group receives 80% of revenues from regulated electric operations, has an

[27] In my testimony, I present financial results using both mean and medians as measures of central tendency. However, due to outliers among means, I have used the median as a measure of central tendency.
[28] I have eliminated Great Plains Energy and Westar Energy due to their announced merger.

average BBB+ issuer credit rating from S&P and an average Baa1 long-term rating from Moody's, a current common equity ratio of 48.0%, and an earned return on common equity of 9.2%.

I use credit ratings to assess the riskiness of KCPL to the proxy groups. Exhibit JRW-4 also shows S&P and Moody's issuer credit ratings for the companies in the two groups. KCPL's issuer credit ratings are BBB+ according to S&P and Baa1 according to Moody's. These ratings are the same as the average S&P and Moody's issuer credit ratings for the Electric and Hevert Proxy Groups (BBB+ and Baa1). Therefore, I believe that KCPL's investment risk is similar to the investment risk of the Electric and Hevert Proxy Groups.

In addition, on page 2 of Exhibit JRW-4, I have assessed the riskiness of the two proxy groups using five different risk measures. These measures include Beta, Financial Strength, Safety, Earnings Predictability, and Stock Price Stability. These risk measures suggest that the two proxy groups are similar in risk. The comparisons of the risk measures include Beta (0.70 vs. 0.72), Financial Strength (A vs. A) Safety (2.0 vs. 2.0), Earnings Predictability (78 vs. 82), and Stock Price Stability (96 vs. 96). On balance, these measures suggest that the two proxy groups are similar.

E. Capital Structure Ratios and Debt Cost Rates

The Company has proposed to use KCPL's capital structure which consists of 50.12% long-term debt and 49.88% common equity based on KCPL's projected capital structure as of December 31, 2016. KCPL recommended a long-term debt cost rate of 5.51%.

As I indicated earlier, I understand that it has been Staff's position to continue the use of GPE's capital structure and debt costs to set KCPL's rates. I understand Staff's past observations about GPE's financing decisions being performed on a consolidated basis. Additionally, I understand that S&P still rates KCPL's and GMO's debt based on GPE's consolidated financial risk profile. As of June 30, 2016, this capital structure includes 50.41% long-term debt, 0.52% preferred stock, and 49.07% common equity. I have adjusted these amounts since the Company redeemed the preferred stock in August. I have allocated the preferred stock amounts equally to long-term debt and common equity. As a result, I am recommending a capital structure of 50.8% long-term debt and 49.2% common equity.

The use of GPE's capital structure and cost of debt as compared to KCPL's, results in a revenue requirement that is about $1 million lower. Because GPE has managed its utility finances on a consolidated basis and KCPL's cost of debt is higher than its weaker affiliate, GMO, it is fair to continue the use of GPE's consolidated capital structure and capital costs for setting KCPL's rates. However, the primary difference in my recommended rate of return and the Company's is our common equity cost estimates.

As shown in Exhibit JRW-4, the median common equity ratios of the Electric and Hevert Proxy Groups are 47.1% and 48.0%, respectively. GPE's capitalization has slightly more equity and less financial risk than the average current capitalizations of electric utility companies. It should be noted that these capitalization ratios for the proxy groups include total debt which consists of both short-term and long-term debt. In assessing financial risk, short-term debt is included because, just like long-term debt, short-term has a higher claim on the assets and earnings of the company and requires timely payment of interest and repayment of principal.

GPE's and KCPL's cost of debt of 5.51% is upwardly biased due to their blending of the yield-to-maturity and simple interest/amortization methods. They should use one or the other, but blending them causes a double counting of issuance expenses, discounts and premiums. After correcting this error, GPE's cost of debt is 5.42% as of June 30, 2016.

F. The Cost of Common Equity Capital

1. <u>Overview</u>

In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services and the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. Because of the lack of competition and the essential nature of their services, it is not appropriate to permit monopoly utilities to set their own prices. Thus, regulation seeks to establish prices that are fair to consumers and, at the same time, sufficient to meet the operating and capital costs of the utility (i.e., provide an adequate return on capital to attract investors).

The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of a company or firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit are costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns, and the market value must equal the book value of the firm's securities.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

1. The Relationship Between Return on Equity, the Cost of Equity, and Market-to-Book Ratios

James M. McTaggart, founder of the international management consulting firm Marakon Associates, described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[29]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.

[29] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1986), page 3.

> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm that earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm that earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

This relationship is discussed in a classic Harvard Business School case study entitled "Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[30]

> For a given industry, more profitable firms – those able to generate higher returns per dollar of equity– should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.

Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I performed a regression study between estimated ROE and market-to-book ratios using natural gas distribution, electric utility, and water utility companies. I used all companies in these three industries that are covered by *Value Line* and have estimated ROE and market-to-book ratio data. The results are presented in Panels A-C of Exhibit JRW-6. The average R-squares for the electric, gas, and water companies

[30] Benjamin Esty, "Note on Value Drivers," Harvard Business School, Case No. 9-297-082, April 7, 1997.

are 0.77, 0.56, and 0.75, respectively.[31] This demonstrates the strong positive relationship between ROEs and market-to-book ratios for public utilities.

2. Indicators of Public Utility Capital Cost Rates

Exhibit JRW-7 provides indicators of public utility equity cost rates over the past decade.

Page 1 shows the yields on long-term A-rated public utility bonds. These yields decreased from 2000 until 2003, and then hovered in the 5.50%-6.50% range from mid-2003 until mid-2008. These yields spiked up to the 7.75% range with the onset of the Great Recession financial crisis, and remained high and volatile until early 2009. These yields declined to below 4.0% in mid-2013, and then increased with interest rates in general to the 4.85% range as of late 2013. They subsequently declined to below 4.0% in the first quarter of 2015, increased with interest rates in general in 2015, and have now dropped back to the 4.0% range.

Page 2 provides the dividend yields for electric utilities over the past decade. The dividend yields for this electric group have declined from the year 2000 to 2007, increased to 5.2% in 2009, and declined to about 3.75% in 2014 and 2015.

Average earned returns on common equity and market-to-book ratios for electric utilities are on page 3 of Exhibit JRW-7. For the electric group, earned returns on common equity have declined gradually since the year 2000 and have been in the 9.0% range in recent years. The average market-to-book ratios for this group peaked at 1.68X in 2007, declined to 1.07X in 2009, and have increased since that time. As of 2015, the average market-to-book for the group was 1.55X. This means that, for at least the last decade, returns on common equity have been greater than the cost of capital, or more than necessary to meet investors' required returns. This also means that customers have been paying more than necessary to support an appropriate profit level for regulated utilities.

3. The Cost of Common Equity

The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed

[31] R-square measures the percent of variation in one variable (e.g., market-to-book ratios) explained by another variable (e.g., expected ROE). R-squares vary between zero and 1.0, with values closer to 1.0 indicating a higher relationship between two variables.

judgment. This return requirement of the stockholder should be commensurate with the return requirement on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as current conditions in the economy and the financial markets.

The expected or required rate of return on common stock is a function of market-wide as well as company-specific factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. The relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries.

Exhibit JRW-8 provides an assessment of investment risk for 97 industries as measured by beta, which according to modern capital market theory, is the only relevant measure of investment risk. These betas come from the *Value Line Investment Survey.* The study shows that the investment risk of utilities is very low. The average betas for electric, water, and gas utility companies are 0.72, 0.74, and 0.71, respectively. As such, the cost of equity for utilities is among the lowest of all industries in the U.S.

2. DCF Analysis

Overview

I rely primarily on the DCF model to estimate the cost of equity capital. Given the investment valuation process and the relative stability of the utility business, I believe that the DCF model provides the best measure of equity cost rates for public utilities. I have also performed a CAPM study; however, I give these results less weight because I believe that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities.

According to the DCF model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a *pro rata* share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore, this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{D_n}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model ("DDM"). The stages in a three-stage DCF model are presented in Exhibit JRW-9, Page 1 of 2. This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a maturity (or steady-state) stage. The dividend-payment stage of a firm depends on the profitability of its internal investments which, in turn, is largely a function of the life cycle of the product or service.

> 1. Growth stage: Characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.
>
> 2. Transition stage: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.
>
> 3. Maturity (steady-state) stage: Eventually, the company reaches a position where its new investment opportunities offer, on average, only slightly attractive ROEs. At that time, its earnings growth rate, payout ratio, and ROE stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

The Constant Growth DCF Model

Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

> where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves fork in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

In my opinion, the economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. However, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and the expected growth rate). The dividend yield can be measured precisely at any point in time; however, it tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Dividend Yield

I have calculated the dividend yields for the companies in the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices. These dividend yields are provided in Panel A of page 2 of Exhibit JRW-10. For the Electric Proxy Group, the median dividend yields using the 30-day, 90-day, and 180-day average stock prices range from 3.3% to 3.4%. I am using the average of the medians - 3.35% - as the dividend yield for the Electric Proxy Group. The dividend yields for the Hevert Proxy Group are shown in Panel B of page 2 of Exhibit JRW-10. The median dividend yields range from 3.3% to 3.4% using the 30-day, 90-day, and 180-day average stock prices. I am using the average of the medians – 3.35% - as the dividend yield for the Hevert Proxy Group.

According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by: (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm that pays dividends on a quarterly basis.[32]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

Given this discussion, I adjust the dividend yield by one-half (1/2) of the expected growth so as to reflect growth over the coming year. The DCF equity cost rate ("K") is computed as:

$$K = [\ (D/P) * (1 + 0.5g)\ ] + g$$

The DCF Growth Rate

There is debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component reflects investors' expectation of the long-term dividend growth rate. Presumably, investors use some combination of historical and/or projected growth rates for earnings and dividends per share and for internal or book-value growth to assess long-term potential.

I have analyzed a number of measures of growth for companies in the proxy groups. I reviewed *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). In addition, I utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Yahoo, Reuters and Zacks. These services solicit five-year earnings growth rate projections from securities analysts and compile and publish the means and medians of these forecasts. Finally, I also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Historical growth rates for EPS, DPS, and BVPS are readily available to investors and are presumably an important ingredient in forming expectations concerning future growth.

[32] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould, at 62 (April 1980).

However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years) is unlikely to accurately measure investors' expectations, due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Analysts' EPS forecasts for companies are collected and published by a number of different investment information services, including Institutional Brokers Estimate System ("I/B/E/S"), Bloomberg, FactSet, Zacks, First Call, and Reuters, among others. Thompson Reuters publishes analysts' EPS forecasts under different product names, including I/B/E/S, First Call, and Reuters. Bloomberg, FactSet, and Zacks publish their own set of analysts' EPS forecasts for companies. These services do not reveal: (1) the analysts who are solicited for forecasts; or (2) the identity of the analysts who actually provide the EPS forecasts that are used in the compilations published by the services. I/B/E/S, Bloomberg, FactSet, and First Call are fee-based services. These services usually provide detailed reports and other data in addition to analysts' EPS forecasts. Thompson Reuters and Zacks do provide limited EPS forecast data free-of-charge on the internet. Yahoo finance (http://finance.yahoo.com) lists Thompson Reuters as the source of its summary EPS forecasts. The Reuters website (www.reuters.com) also publishes EPS forecasts from Thompson Reuters, but with more detail. Zacks (www.zacks.com) publishes its summary forecasts on its website. Zacks estimates are also available on other websites, such as msn.money (http://money.msn.com).

The following example provides the EPS forecasts compiled by Reuters for Alliant Energy Corp. (stock symbol "LNT"). The figures are provided on page 2 of Exhibit JRW-9. Line one shows that one analyst has provided EPS estimates for the quarter ending December 31, 2016. The mean, high and low estimates are $0.18, $0.20, and $0.16, respectively. The second line shows the quarterly EPS estimates for the quarter ending March 31, 2017 of $0.45 (mean), $0.45 (high), and $0.45 (low). Line three shows the annual EPS estimates for the fiscal year ending December 2016 ($2.10 (mean), $2.28 (high), and $1.88 (low). Line four shows the annual EPS estimates for the fiscal year ending December 2017 ($2.22 (mean), $2.32 (high), and $1.97 (low).The quarterly and annual EPS forecasts in lines 1-4 are expressed in dollars and cents. As in the LNT case shown here, it is common for more analysts to provide estimates of annual EPS as opposed to quarterly EPS. The bottom line shows the projected long-term EPS growth rate, which is expressed as a percentage. For LNT, three analysts have provided a long-term EPS growth rate forecast, with mean, high, and low growth rates of 6.60%, 7.20%, and 6.00%.

The DCF growth rate is the long-term projected growth rate in EPS, DPS, and BVPS. Therefore, in developing an equity cost rate using the DCF model, the projected long-term growth rate is the projection used in the DCF model. However, there are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates. First, the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate. Nonetheless, over the very long term, dividend and earnings will have to grow at a similar growth rate. Therefore, consideration must be given to other indicators of growth, including prospective dividend growth, internal growth, as well as projected earnings growth. Second, a recent study by Lacina, Lee, and Xu (2011) has shown that analysts' long-term earnings growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings.[33] Employing data over a twenty-year period, these authors demonstrate that using the most recent year's EPS figure to forecast EPS in the next 3-5 years proved to be just as accurate as using the EPS estimates from analysts' long-term earnings growth rate forecasts. In the authors' opinion, these results indicate that analysts' long-term earnings growth rate forecasts should be used with caution as inputs for valuation and cost of capital purposes. Finally, and most significantly, it is well known that the long-term EPS growth

[33] M. Lacina, B. Lee & Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101.

rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. This has been demonstrated in a number of academic studies over the years.[34] Hence, using these growth rates as a DCF growth rate will provide an overstated equity cost rate. On this issue, a study by Easton and Sommers (2007) found that optimism in analysts' growth rate forecasts leads to an upward bias in estimates of the cost of equity capital of almost 3.0 percentage points.[35]

Page 3 of Exhibit JRW-10 provides the 5- and 10-year historical growth rates for EPS, DPS, and BVPS for the companies in the two proxy groups, as published in the *Value Line Investment Survey*. The median historical growth measures for EPS, DPS, and BVPS for the Electric Proxy Group, as provided in Panel A, range from 3.5% to 5.5%, with an average of the medians of 4.2%. For the Hevert Proxy Group, as shown in Panel B of page 3 of Exhibit JRW-10, the historical growth measures in EPS, DPS, and BVPS, as measured by the medians, range from 3.3% to 6.5%, with an average of the medians of 4.5%.

Value Line's projections of EPS, DPS, and BVPS growth for the companies in the proxy groups are shown on page 4 of Exhibit JRW-10. As stated above, due to the presence of outliers, the medians are used in the analysis. For the Electric Proxy Group, as shown in Panel A of page 4 of Exhibit JRW-10, the medians range from 4.0% to 5.5%, with an average of the medians of 4.9%. The range of the medians for the Hevert Proxy Group, shown in Panel B of page 4 of Exhibit JRW-10, is from 4.0 % to 5.5 %, with an average of the medians of 4.9%.

Also provided on page 4 of Exhibit JRW-10 are the prospective sustainable growth rates for the companies in the two proxy groups as measured by *Value Line*'s average projected retention rate and return on shareholders' equity. As noted above, sustainable growth is a significant and a primary driver of long-run earnings growth. For the Electric and Hevert Proxy Groups, the median prospective sustainable growth rates are 3.8% and 3.6%, respectively.

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[34] The studies that demonstrate analysts' long-term EPS forecasts are overly-optimistic and upwardly biased include: R.D. Harris, "The Accuracy, Bias, and Efficiency of Analysts' Long Run Earnings Growth Forecasts," *Journal of Business Finance & Accounting*, pp. 725-55 (June/July 1999); P. DeChow, A. Hutton, and R. Sloan, "The Relation Between Analysts' Forecasts of Long-Term Earnings Growth and Stock Price Performance Following Equity Offerings," *Contemporary Accounting Research (2000);* K. Chan, L., Karceski, J., & Lakonishok, J., "The Level and Persistence of Growth Rates," *Journal of Finance* pp. 643−684, (2003); M. Lacina, B. Lee and Z. Xu, *Advances in Business and Management Forecasting (Vol. 8),* Kenneth D. Lawrence, Ronald K. Klimberg (ed.), Emerald Group Publishing Limited, pp.77-101; and Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17, (Spring 2010).

[35] Peter D. Easton & Gregory A. Sommers, *Effect of Analysts' Optimism on Estimates of the Expected Rate of Return Implied by Earnings Forecasts*, 45 J. ACCT. RES. 983–1015 (2007).

As noted above, Yahoo, Zacks, and Reuters collect, summarize, and publish Wall Street analysts' long-term EPS growth rate forecasts for the companies in the proxy groups. These forecasts are provided for the companies in the proxy groups on page 5 of Exhibit JRW-10. I have reported both the mean and median growth rates for the groups. Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected five-year EPS growth rates from the three services for each company to arrive at an expected EPS growth rate for each company. The mean/median of analysts' projected EPS growth rates for the Electric and Hevert Proxy Groups are 4.5%/5.2% and 5.3%/5.5%, respectively.[36]

Page 6 of Exhibit JRW-10 shows the summary DCF growth rate indicators for the proxy groups. The historical growth rate indicators for my Electric Proxy Group imply a baseline growth rate of 4.2%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 4.8%, and *Value Line*'s projected sustainable growth rate is 3.8%. The projected EPS growth rates of Wall Street analysts for the Electric Proxy Group are 4.5% and 5.2% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators (ignoring historical growth) is 3.8% to 5.2%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate is 5.0%. This growth rate figure is clearly in the upper end of the range of historic and projected growth rates for the Electric Proxy Group.

For the Hevert Proxy Group, the historical growth rate indicators indicate a growth rate of 4.5%. The average of the projected EPS, DPS, and BVPS growth rates from *Value Line* is 4.9%, and *Value Line*'s projected sustainable growth rate is 3.6%. The projected EPS growth rates of Wall Street analysts are 5.3% and 5.5% as measured by the mean and median growth rates. The overall range for the projected growth rate indicators is 3.6% to 5.5%. Giving primary weight to the projected EPS growth rate of Wall Street analysts, I believe that the appropriate projected growth rate range is 5.30%. This growth rate figure is clearly in the upper end of the range of historic and projected growth rates for the Hevert Proxy Group.

[36] Given variation in the measures of central tendency of analysts' projected EPS growth rates proxy groups, I have considered both the means and medians figures in the growth rate analysis.

DCF Equity Cost Rate Summary

My DCF-derived equity cost rates for the groups are summarized on page 1 of Exhibit JRW-10 and in Table 1 below.

Table 1
DCF-derived Equity Cost Rate/ROE

	Dividend Yield	1 + ½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Electric Proxy Group	**3.35%**	**1.02500**	**5.00%**	**8.45%**
Hevert Proxy Group	**3.35%**	**1.02650**	**5.30%**	**8.75%**

The result for the Electric Proxy Group is the 3.35% dividend yield, times the one and one-half growth adjustment of 1.025, plus the DCF growth rate of 5.0%, which results in an equity cost rate of 8.45%. The result for the Hevert Proxy Group is 8.75% which includes a dividend yield of 3.35%, an adjustment factor of 1.0265, and a DCF growth rate of 5.30%.

3. Capital Asset Pricing Model

Overview

The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

> The yield on long-term U.S. Treasury securities is normally used as Rf. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk, and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + ß * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;

- (R_f) represents the risk-free rate of interest;
- *[E(R_m) - (R_f)]* represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—(ß) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta (ß), and the expected equity or market risk premium $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is represented by the yield on long-term U.S. Treasury bonds. ß, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium $(E(R_m) - (R_f))$. I will discuss each of these inputs below.

Exhibit JRW-11 provides the summary results for my CAPM study. Page 1 shows the results, and the following pages contain the supporting data.

The Risk-Free Interest Rate

The yield on long-term U.S. Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term U.S. Treasury bonds, in turn, has been considered to be the yield on U.S. Treasury bonds with 30-year maturities.

As shown on page 2 of Exhibit JRW-11, the yield on 30-year U.S. Treasury bonds has been in the 2.5% to 4.0% range over the 2013–2016 time period. The 30-year Treasury yield is currently in the bottom half of this range. Given the recent range of yields and the possibility of higher interest rates, I use 4.0% as the risk-free rate, or R_f, in my CAPM.

My 4.0% risk-free interest rate takes into account the range of interest rates in the past and effectively synchronizes the risk-free rate with the market risk premium ("MRP"). I am not making an explicit forecast of higher interest rates. The risk-free rate and the MRP are interrelated in that the MRP is developed in relation to the risk-free rate. As discussed below, my MRP is based on the results of many studies and surveys that have been published over time. Therefore, my risk-free interest rate of 4.0% is effectively a normalized risk-free rate of interest.

Beta

Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return.

As shown on page 3 of Exhibit JRW-11, the slope of the regression line is the stock's ß. A steeper line indicates that the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater-than-average market risk. A less steep line indicates a lower ß and less market risk.

Several online investment information services, such as Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to: (1) the time period over which ß is measured; and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the proxy groups, I am using the betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 3 of Exhibit JRW-11, the median betas for the companies in the Electric and Hevert Proxy Groups are 0.70 and 0.70, respectively.

The Market Risk Premium ("MRP")

The MRP is equal to the expected return on the stock market (e.g., the expected return on the S&P 500, $E(R_m)$ minus the risk-free rate of interest (R_f)). The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the MRP is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market - $E(R_m)$. As is discussed below, there are different ways to measure $E(R_m)$, and studies have come up with significantly different magnitudes for $E(R_m)$. As Merton Miller, the 1990 Nobel Prize winner in economics indicated, $E(R_m)$ is very difficult to measure and is one of the great mysteries in finance.[37]

> Page 4 of Exhibit JRW-11 highlights the primary approaches to, and issues in, estimating the expected MRP. The traditional way to measure the MRP was to use the difference between historical

[37] Merton Miller, "The History of Finance: An Eyewitness Account," *Journal of Applied Corporate Finance*, 2000, page 3.

average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, were used as the measures of the market's expected return (known as the *ex ante* or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson, who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium range of 5% to 7% above the rate on long-term U.S. Treasury bonds. However, this can be a problem because: (1) ex post returns are not the same as *ex ante* expectations; (2) market risk premiums can change over time, increasing when investors become more risk-averse and decreasing when investors become less risk-averse; and (3) market conditions can change such that ex post historical returns are poor estimates of *ex ante* expectations.

The use of historical returns as market expectations has been criticized in numerous academic studies as discussed later in my testimony. The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute *ex ante* expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[38]

In addition, there are a number of surveys of financial professionals regarding the MRP. There have also been several published surveys of academics on the equity risk premium. *CFO Magazine* conducts a quarterly survey of CFOs, which includes questions regarding their views on the current expected returns on stocks and bonds. Usually, over 500 CFOs participate in the survey.[39] Questions regarding expected stock and bond returns are also included in the Federal Reserve Bank of Philadelphia's annual survey of financial forecasters, which is published as the *Survey of Professional Forecasters*.[40] This survey of professional

[38] Rajnish Mehra & Edward C. Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics,* 145 (1985).
[39] *See* DUKE/CFO Magazine Global Business Outlook Survey, www.cfosurvey.org, September, 2016).
[40] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters (Feb, 2016).* The Survey of Professional Forecasters was formerly conducted by the American Statistical Association ("ASA") and the National Bureau of Economic Research ("NBER") and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

economists has been published for almost fifty years. In addition, Pablo Fernandez conducts annual surveys of financial analysts and companies regarding the equity risk premiums they use in their investment and financial decision-making.[41]

Derrig and Orr (2003), Fernandez (2007), and Song (2007) have completed the most comprehensive reviews to date of the research on the MRP.[42] Derrig and Orr's study evaluated the various approaches to estimating MRPs, as well as the issues with the alternative approaches and summarized the findings of the published research on the MRP. Fernandez examined four alternative measures of the MRP – historical, expected, required, and implied. He also reviewed the major studies of the MRP and presented the summary MRP results. Song provides an annotated bibliography and highlights the alternative approaches to estimating the MRP.

Page 5 of Exhibit JRW-11 provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr, Fernandez, and Song, as well as other more recent studies of the MRP. These include the results of: (1) the various studies of the historical risk premium, (2) *ex ante* MRP studies, (3) MRP surveys of CFOs, financial forecasters, analysts, companies and academics, and (4) the Building Blocks approach to the MRP. There are results reported for over thirty studies, and the median MRP is 4.63%.

The studies cited on page 5 of Exhibit JRW-11 include every MRP study and survey I could identify that was published over the past decade and that provided an MRP estimate. Most of these studies were published prior to the financial crisis. In addition, some of these studies were published in the early 2000s at the market peak. It should be noted that many of these studies (as indicated) used data over long periods of time (as long as fifty years of data) and so were not estimating an MRP as of a specific point in time (e.g., the year 2001). To assess the effect of the earlier studies on the MRP, I have reconstructed page 5 of Exhibit JRW-11 on page 6 of Exhibit JRW-11; however, I have eliminated all studies dated before January 2, 2010. The median for this subset of studies is 4.95%.

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[41] Pablo Fernandez, Alberto Ortiz and Isabel Fernandez Acín, "Market Risk Premium used in 71 countries in 2016: a survey with 6,932 answers: survey," May 9, 2016.

[42] *See* Richard Derrig & Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, (August 28, 2003); Pablo Fernandez, "Equity Premium: Historical, Expected, Required, and Implied," IESE Business School Working Paper, (2007); Zhiyi Song, "The Equity Risk Premium: An Annotated Bibliography," CFA Institute, (2007).

> Much of the data indicates that the market risk premium is in the 4.0% to 6.0% range. Several recent studies (such as Damodaran, American Appraisers, Duarte and Rosa, Duff & Phelps, and the CFO Survey have suggested an increase in the market risk premium. Therefore, I will use 5.5%, which is in the upper end of the range, as the market risk premium or MRP. This MRP is consistent with the following MRPs

1. The September 2016 CFO survey conducted by *CFO Magazine* and Duke University, which included about 450 responses, the expected 10-year MRP was 4.25%.[43]
2. The financial forecasters in the previously referenced Federal Reserve Bank of Philadelphia survey projected both stock and bond returns. In the February 2016 survey, the median long-term expected stock and bond returns were 5.34% and 3.44%, respectively. This provides an expected MRP of 1.90% (5.34%-3.44%).
3. Pablo Fernandez published the results of his 2016 survey of academics, financial analysts, and companies.[44] This survey included over 4,000 responses. The median MRP employed by U.S. analysts and companies was 5.3%.
4. Duff & Phelps is a well-known valuation and corporate finance advisor that publishes extensively on the cost of capital. As of 2016, Duff & Phelps recommended using a 5.5% MRP for the U.S.[45]
5. CAPM Equity Cost Rate

The results of my CAPM study for the proxy groups are summarized on page 1 of Exhibit JRW-11 and in Table 2 below.

Table 2
CAPM-derived Equity Cost Rate/ROE
$K = (R_f) + ß * [E(R_m) - (R_f)]$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Electric Proxy Group	**4.0%**	**0.70**	**5.5%**	**7.9%**
Hevert Proxy Group	**4.0%**	**0.70**	**5.5%**	**7.9%**

For the Electric Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.70 times the equity risk premium of 5.5% results in a 7.9% equity cost rate. For the Hevert Proxy Group, the risk-free rate of 4.0% plus the product of the beta of 0.70 times the equity risk premium of 5.5% results in a 7.9% equity cost rate.

43 *Id.* p. 67.
44 *Id.* p. 3.
45 http://www.duffandphelps.com/insights/publications/cost-of-capital/index

4. <u>Equity Cost Rate Summary</u>

Overview

My DCF analyses for the Electric and Hevert Proxy Groups indicate equity cost rates of 8.45% and 8.75%, respectively. The CAPM equity cost rates for the Electric and Hevert Proxy Groups are both 7.9%.

Table 3
ROEs Derived from DCF and CAPM Models

	DCF	CAPM
Electric Proxy Group	**8.45%**	**7.90%**
Hevert Proxy Group	**8.75%**	**7.90%**

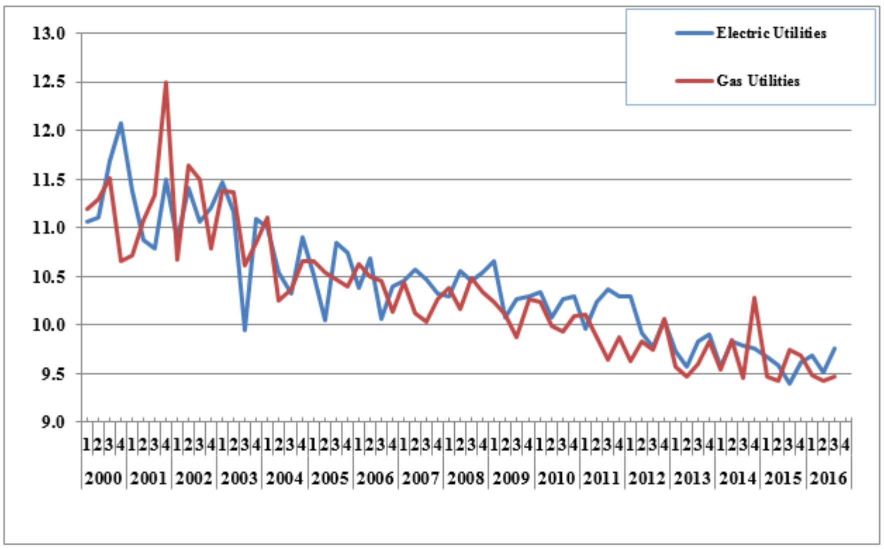
Given these results, I conclude that the appropriate equity cost rate for companies in the Electric and Hevert Proxy Groups is in the 7.90% to 8.75% range. However, since I rely primarily on the DCF model, I am using the upper end of the range as the equity cost rate. Therefore, I conclude that the appropriate equity cost rate for the groups is 8.65%. This recommendation gives primary weight to the DCF results for the Proxy Groups.

There are a number of reasons why an equity cost rate of 8.65% is appropriate and fair for the Company in this case:

1. I have employed a capital structure that has a slightly higher common equity ratio and therefore slightly lower financial risk than the capital structures of the two proxy groups;
2. As shown in Exhibits JRW-2 and JRW-3, capital costs for utilities, as indicated by long-term bond yields, are still at historically low levels. In addition, given low inflationary expectations and slow global economic growth, interest rates are likely to remain at low levels for some time;
3. As shown in Exhibit JRW-8, the electric utility industry is among the lowest risk industries in the U.S. as measured by beta. As such, the cost of equity capital for this industry is amongst the lowest in the U.S., according to the CAPM;
4. The investment risk of KCPL, as indicated by the Company's S&P and Moody's issuer credit rating of BBB+ and Baa1, are equal to the averages of the Electric and Hevert Proxy Groups; and
5. These authorized ROEs for electric utilities have decreased over the years. As shown in Figure 5, the average authorized ROE for electric utilities has declined from 10.01% in 2012, to 9.8% in 2013, to 9.76% in 2014, 9.58% in 2015, and 9.64% in the first three quarters of 2016,

according to Regulatory Research Associates.[46] In my opinion, these authorized ROEs have lagged behind capital market cost rates, or in other words, authorized ROEs have been slow to reflect low capital market cost rates. This has been especially true in recent years as some state commissions have been reluctant to authorize ROEs below 10%. However, the trend has been towards lower ROEs, and the norm now is below ten percent. Hence, I believe that my recommended ROE reflects our present historically low capital cost rates, and these low capital cost rates are finally being recognized by state utility commissions.

Figure 5
Authorized ROEs for Electric Utility and Gas Distribution Companies
2000-2016



Authorized ROEs and Credit Quality

Moody's recently published an article on utility ROEs and credit quality. In the article, Moody's recognizes that authorized ROEs for electric and gas companies are declining due to lower interest rates.[47]

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinize

[46] *Regulatory Focus*, Regulatory Research Associates, January, 2016. The electric utility authorized ROEs exclude the authorized ROEs in Virginia which include generation adders and thus are inflated and also inappropriate comparisons for a company like Delmarva.
[47] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

> their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures.

Moody's indicates that with the lower authorized ROEs, electric and gas companies are earning ROEs of 9.0% to 10.0%, but this is not impairing their credit profiles and is not deterring them from raising record amounts of capital. With respect to authorized ROEs, Moody's recognizes that utilities and regulatory commissions are having trouble justifying higher ROEs in the face of lower interest rates and cost recovery mechanisms.[48]

> Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

Overall, this article further supports the prevailing/emerging belief that lower authorized ROEs are unlikely to hurt the financial integrity of utilities or their ability to attract capital.

Hope and Bluefield Standards

As previously noted, according to the *Hope* and *Bluefield* decisions, returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital. KCP&L's S&P credit rating is in line with the average of the Electric and Hevert Proxy Groups. While my recommendation is below the average authorized ROEs for electric utility companies, it reflects the downward trend in authorized and earned ROEs of electric utility companies. As is highlighted in the Moody's publication cited above, despite authorized and earned ROEs below 10%, the credit quality of electric and gas companies has not been impaired and, in fact, has improved and utilities are raising about $50 billion per year in capital. Major positive factors in the improved credit quality

[48] Moody's Investors Service, "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

of utilities are regulatory ratemaking mechanisms. Therefore, I do believe that my ROE recommendation meets the criteria established in the *Hope* and *Bluefield* decisions.

> Figure 6 provides a market-based test on the adequacy of my 8.65% ROE recommendation. The current earned ROE's for electric utilities has been in the 9.0% range (9.1% for the Electric Proxy Group and 9.2% for the Hevert Proxy Group). In Figure 5, I show the performance of the Dow Jones Utilities ("DJU") versus the S&P 500 since January 1, 2016. Clearly an earned ROE of about 9.0% is much more than adequate to meet investors' return requirements. The DJU is up over 13.65% year-to-date, while the S&P 500 (labelled as GSPC in the graph in Figure 2) is up only 2.63%. As such, in my opinion, my 8.65% ROE recommendation, which is less than 50 basis points below these earned ROEs, is adequate to meet investors' return requirements.

Figure 6
Dow Jones Utilities vs. the S&P 500
January 1 – November 4, 2016
Source: https://finance.yahoo.com/

Source: https://finance.yahoo.com/

Staff Expert/Witness: J. Randall Woolridge

V. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff recommends plant-in-service ("plant") and accumulated depreciation reserve ("reserve") balances be based on actual booked amounts as of the end of the update period, June 30, 2016. This includes plant additions that have occurred since the test year ending

December 31, 2015, and the related depreciation reserve balances. At the time of the true-up audit, adjustments to the plant balances Staff used for its direct filing will be updated to include amounts for plant additions that have become fully operational and used for service as of December 31, 2016, the ending point of the true-up period. Staff will also include depreciation reserve balances related to all plant, including those additions and retirements. Plant must be "fully operational and used for service" before it is appropriate to reflect that plant and its associated reserve in rates.

The plant for KCPL for the period ending June 30, 2016, is identified on the Plant Accounting Schedule- Schedule 3, and the accumulated depreciation reserve as of that date is identified in the Depreciation Reserve Accounting Schedule- Schedule 6. The information in Accounting Schedules 3 & 6 for plant and reserve are shown by Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA") for each plant category, broken out for production, transmission, distribution and general facilities.

It is necessary for both KCPL and Staff to make adjustments to the plant reserve balances to account for retirement work in progress ("RWIP"). RWIP is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage. KCPL removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates. However, as of June 30, 2016, KCPL had not removed the related reserve amounts associated with cost of removal and salvage accruals calculated for the retired plant included in the RWIP balance. While the actual plant is retired and removed from plant balance and the related reserve, the plant has not been physically disassembled so the cost of removal and salvage components of depreciation are still included in the reserve. As a result, KCPL's books overstate the reserve for this retired plant that is no longer serving the public. Because the plant that is no longer being used for service is removed from rate base, it is also necessary to make a corresponding adjustment to remove the amounts associated with the retired plant from the reserve balances and for the cost of removal and salvage amounts. Staff included a line item in the Accumulated Depreciation schedule, identifying the RWIP associated with Production, Transmission, Distribution, and General Plant.

Staff requested the plant and reserve amounts by FERC account and, in the case of the production facilities, by individual power plant. KCPL uses an accounting package for plant records called Power Plant. Staff requested plant and reserve information that came directly from the Power Plant record system. As such, the plant and reserve information contained in Accounting Schedules 3 and 6 by the individual plant categories and FERC accounts are those that directly tie back to the books and records of KCPL. Periodically, Staff verifies the actual plant and reserve balances directly back to the Power Plant record system source to substantiate the amounts provided by KCPL in data requests. After the direct filing in this case, Staff intends on performing this verification procedure.

Depreciation expense is based on Staff witness Keenan B. Patterson's recommended depreciation rates that were applied to the adjusted Missouri jurisdictional plant balances as of June 30, 2016. This will be further discussed in the Income Statement section of Staff's Cost of Service Report in the Depreciation Expense section.

The following table identifies KCPL and GMO electric utility generation resources:

Load	**Unit**	**Year Completed**	**Estimated 2016 MW Capacity**	**Primary Fuel**
Base Load	Iatan No. 2	2010	482 (a)	Coal
	Wolf Creek	1985	549 (a)	Nuclear
	Iatan No. 1	1980	499 (a)	Coal
	LaCygne No. 2 343 (a) in 2013	1977	699 combined (a)	Coal
	LaCygne No. 1 368 (a) in 2013	1973	See above	Coal
	Hawthorn No. 5(b)	1969	564	Coal
	Montrose No. 3	1964	176	Coal
	Montrose No. 2	1960	164	Coal
Peak Load	West Gardner Nos. 1-4	2003	311	Natural Gas
	Osawatomie	2003	77	Natural Gas
	Hawthorn Nos. 6 and 9	1997, 2000	235	Natural Gas
	Hawthorn No. 8	2000	79	Natural Gas
	Hawthorn No. 7	2000	78	Natural Gas
	Northeast Black Start Unit	1985	2	Oil
	Northeast Nos. 17-18	1977	105	Oil
	Northeast Nos. 13-14	1976	95	Oil
	Northeast Nos. 15-16	1975	106	Oil
	Northeast Nos. 11-12	1972	93	Oil
Wind	Spearville 2 Wind Energy Facility (c)	2010	15	Wind
	Spearville 1 Wind Energy Facility (d)	2006	31	Wind
Total KCP&L			**4,360 MWs**	

Load	Unit	Year Completed	Estimated 2016 MW Capacity	Primary Fuel
Base Load	Iatan No. 2	2010	159 (a)	Coal
	Iatan No. 1	1980	128 (a)	Coal
	Jeffrey energy Center Nos. 1, 2 and 3	1978, 1980, 1983	172 (a)	Coal
	Sibley Nos.1, 2 and 3	1960, 1962, 1969	461	Coal
	Lake Road Nos. 2 and 4	1957, 1967	115	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	2005	303	Natural Gas
	Crossroads Energy Center	2002	292	Natural Gas
	Ralph Green No. 3	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	1975-1979	247	Natural Gas/Oil
	Lake Road No. 5	1974	62	Natural Gas/Oil
	Lake Road Nos. 1 and 3	1951, 1962	16	Natural Gas/Oil
	Lake Road Nos. 6 and 7	1989, 1990	42	Oil
	Nevada	1974	18	Oil
Total GMO			**2,086 MWs**	
Total Great Plains Energy			**6,446 MWs**	

Source: GREAT PLAINS ENERGY INC. 10-K December 31, 2015, page 22

a. Share of a jointly owned unit.
b. In 2001, a new boiler, air quality control equipment and an uprated turbine was place in service at the Hawthorn Generating Station. The unit was returned to commercial operation in June 2000 following a 1999 explosion.
c. The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards.
d. The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 31 MW pursuant to SPP reliability standards.

KCP&L owns 50% of La Cygne Nos. 1 and 2, 70% of Iatan 1, 55% of Iatan No. 2 and 47% of Wolf Creek. GMO owns 18% of each of Iatan Nos. 1 and 2 and 8% of Jeffrey Energy Center Nos. 1, 2, and 3.

Staff Expert/Witness: Cary G. Featherstone

B. Plant Amortization

Staff evaluated and annualized KCPL's plant amortization expense. Like depreciation expense, plant amortization expense represents the return of the capital costs incurred in relation to intangible assets such as software, land rights, leasehold improvements, and other intangible items. Because these costs are intangible in nature, the plant accounts are not assigned a depreciation rate in the depreciation expense accounting schedule in Staff's EMS Cost of Service schedules. Staff has included the annualized plant amortization expense on Staff Accounting Schedule 10, adjustments E-242-1 and E-247-1.

Staff Expert/Witness: Antonija Nieto

C. Greenwood - Additions to Plant – In-Service Criteria

In 2016, GMO began construction of an approximately 3 megawatt ("MW") direct current ("DC") utility-scale solar facility located near Greenwood, MO; adjacent to the existing Greenwood Energy Center. Staff intended to respond to the in-service evaluation during the true-up portion of the GMO rate case, ER-2016-0156, however, because the case was settled and because Staff's direct position is to allocate the Greenwood facility in part to KCPL, Staff's evaluation of in-service is presented here.

In order to include the solar facility into rate base, the plant must be "fully operational and used for service."[49] In-service criteria are a set of operational tests or operational requirements used to determine whether a new unit is "fully operational and used for service."

A new facility may not have any historical operating information from which the Staff could make a recommendation to the Commission of whether the new unit is "fully operational and used for service"; therefore, operational tests must be established and performed in order for Staff to file its recommendation. In-service criteria are developed based on review of the new unit's specifications and discussions with the Company.

GMO presented in-service criteria in the direct testimony of Tim Rush in ER-2016-0156; Staff agrees that the presented in-service criteria are appropriate for evaluation of the Greenwood solar facility. Based on Staff's review and analysis of the data, the Greenwood Solar facility has met the in-service criteria effective June 20, 2016. Therefore, Staff recommends that the Greenwood Solar facility be considered fully operational and used for service. Additional details regarding Staff's review are attached in Appendix 3, Schedule CME-1.

Staff Expert/Witness: Claire M. Eubanks, PE

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[49] Section 393.135, RSMo. 2000: "Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited." (Emphasis added)

D. Greenwood - Solar Allocation

On November 12, 2015, GMO filed an application, Case No. EA-2015-0256, with the Commission requesting permission and approval of a Certificate of Public Convenience and Necessity ("CCN") authorizing it to construct, install, own, operate, maintain and otherwise control and manage solar generation facilities in Greenwood Missouri ("Greenwood Solar Project"). GMO entered into a Master Service Agreement ("Agreement") with ** ________ ______________________ ** for the engineering, procurement, and construction of the Greenwood Solar Project.[50] The Greenwood Solar Project is a 3 megawatts ("MW") solar facility that will produce approximately 4,700 megawatt-hours ("MWh") of solar energy per year. GMO indicated in its CCN application the Greenwood Solar project was being proposed to gain hands-on solar operation and maintenance skills.[51]

The Commission approved GMO's request for a CCN for the Greenwood Solar Project in its Report and Order effective March 12, 2016. On page 18 of its Report and Order, the Commission stated, "The Commission has found that GMO's proposal to construct a pilot solar plant is necessary or convenient for the public service and will grant the company the certificate of convenience and necessity it seeks."

In addition to granting GMO the CCN for the Greenwood Solar Project, the Commission also addressed concern that GMO ratepayers will bear all the costs of a project that is primarily being built to allow KCPL to gain experience owning, maintaining, and operating a utility scale solar facility. Beginning on page 16 of its Report and Order in Case No. EA-2015-0256, the Commission stated:

> The Commission is concerned that only GMO ratepayers will bear the cost of the project. The Commission will not make any specific ratemaking decisions in this case. Those will be reserved for GMO's pending rate case. However, the matter will once again come before the Commission when GMO seeks to add the plant to its rate base. **At that time, the Commission will expect GMO to propose a means by which those costs will be shared with KCP&L's customers who will also benefit from the lessons learned from this pilot project. [emphasis added]**

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50 KCPL-GMO response to Staff Data Request 6 in Case No. EA-2015-0256.

51 Case No. EA-2015-0256, *Application of KCP&L Greater Missouri Operations Company for Permission and Approval of a Certificate of Public Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage Solar Generation Facilities in Western Missouri*, Pages 3 - 5.

GMO does not have any employees. KCPL employees perform all services for Great Plains Energy, KCPL, and GMO under an operating agreement. The employees that will gain the experience operating a utility scale solar project are KCPL employees. Consequently, all rate districts, KCPL-Missouri, KCPL-Kansas and GMO will benefit from the acquired knowledge from building and operating a utility scale solar facility.

In Case No ER-2016-0156, GMO witness Tim Rush stated that the Greenwood facility was placed in service as of June 20, 2016.[52] In that case, Staff had not completed the in-service criteria for the Greenwood facility as a result of the black box settlement in the GMO rate case. In this report, however, Staff witness Claire M. Eubanks will address the Greenwood facility in-service criteria.

Absent a proposal to allocate a portion of the Greenwood Solar Project costs by KCPL in its direct filing in this case as ordered by the Commission in Case No. EA-2015-0256, Staff is proposing an allocation methodology for the Greenwood Solar Project costs that is included in Staff's Accounting Schedules.

Staff recommends allocating the Greenwood solar capital costs and any related expenses based on number of customers. The Commission addressed in its Order in Case No. EA-2015-0256 the intangible benefits that will be gained from the experience of constructing and operating the facility and the results that will lead to increased use of solar power in the future.[53] Since the experience gained will benefit all of KCPL and GMO's customers in the future, allocating the costs using customers is a reasonable approach. The table below reflects the allocation between KCPL and GMO using customers:[54]

Methodology	KCPL	%	GMO	%	Total
Customers	524,999	62.27%	318,150	37.73%	843,149

The adjustment to allocate capital costs is reflected on Schedule 4 of Staff's Accounting Schedules, Adjustment P-233.1. At the time of Staff's Direct filing, KCPL has not incurred any maintenance costs for the Greenwood Solar facility. Staff also recommends that maintenance

[52] Rush rebuttal testimony in Case No. ER-2016-0156, page 21.
[53] Case No. EA-2015-0256 Commission Report and Order, page 16.
[54] Data from KCPL, MPS, and L&P Annual Report filed on May 31, 2016.

costs associated with the Greenwood Solar facility be allocated in the same manner to the extent KCPL incurs maintenance costs through the true-up period, December 31, 2016.

Since the Greenwood Solar Project is being built to gain experience owning, operating, and maintaining a utility scale solar facility with KCPL employees gaining the experience, Staff also recommends that the costs of the Greenwood Solar project be allocated to KCPL to include the Kansas jurisdiction. Staff utilizes a demand allocator to allocate production plant and reserve costs between Kansas and Missouri. Staff used the same approach to allocate the Greenwood Solar Project between Missouri and Kansas in Staff Accounting Schedule 3.

Staff Expert/Witness: Karen Lyons

E. Material and Supplies

Staff's recommended treatment of materials and supplies is to examine each account individually in order to determine an appropriate level that most accurately reflects the ongoing future investment costs of a particular account that should be included in rate base. Materials and supplies represent an investment in inventory for items such as spare parts, electric cables, poles, meters, and other miscellaneous items used in daily operations, maintenance, and construction activities by KCPL to maintain and build KCPL's production facilities and electric system. Because the account balances varied greatly depending on each individual account, Staff reviewed the balances for each account for materials and supplies individually on a monthly basis to determine whether trends within an individual account existed over time. Staff reviewed the monthly balances for materials and supplies accounts from December 2014 to December 2015. If an upward or downward trend was detected, then Staff used the ending balance for that account. If there was no discernible trend, then a 13-month average was determined to be the most appropriate measure of the ongoing investment level for that account. Staff examined the accounts individually and determined which methodology, 13-month average or ending balance, was the most appropriate measure to accurately predict the ongoing future investment costs of a particular account that should be included in rate base (Accounting Schedule 2).

Staff Expert/Witness: Michael Jason Taylor

F. Prepayments

Staff's recommended treatment of prepayments is to examine each prepayment account individually in order to determine an appropriate measure that most accurately predicts the ongoing future investment costs of a particular prepayment account, and then to include the appropriate level of prepayments in KCPL's rate base. Prepayments are expenses a company pays in advance of the associated good or service purchased. Since there are investment costs incurred by the utility when it prepays expenses, the company is allowed to earn a return on these amounts through inclusion in rate base. For example, KCPL prepays for a property insurance policy to protect its assets in advance of the coverage period. Accordingly, the cost of that insurance policy is considered to be a prepaid asset and included in rate base. As the prepayments are consumed, an amount is charged to an expense account in the income statement. Staff included amounts in its rate base for all prepayments required for KCPL to provide electric utility service to its customers. Staff examined all of KCPL's prepayment account balances from June 2015 to June 2016, on a month-by-month basis. Based on this review, and the variability in the monthly account balances, Staff determined the prepayment levels to be included in KCPL's rate base. For accounts where there was no discernible upward or downward trend in the monthly balances, Staff calculated an average based on balances for the 13-months ending June 30, 2016. For accounts where a noticeable upward or downward trend was present, Staff used the most recent account balances (June 30, 2016). The Commission should base its awarded revenue requirement on Staff's recommended appropriate measure of prepayments added to KCPL's rate base, as indicated in Accounting Schedule 2.

Staff Expert/Witness: Michael Jason Taylor

G. Cash Working Capital

Cash Working Capital (CWC) is the amount of cash necessary for a utility to pay the day-to-day expenses incurred to provide utility services to its customers. Cash inflows from payments received by the company from its customers for the provision of utility service and cash outflows for expenses paid by the company in providing that utility service are analyzed using a lead/lag study. KCPL and Staff are using the same expense lags agreed to by both parties in the 2014 rate case. Staff has reviewed the methodology described by KCPL witness

Ronald A. Klote concerning the calculation of the revenue lag and is using the same revenue lags as outlined on pages 28 and 29 of his direct testimony.

When the company expends funds to pay an expense before its customers provide the cash, the shareholders are the source of the funds. This cash represents a portion of the shareholders' total investment in the company. The shareholders are compensated for the CWC funds they provide by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the funds they have invested.

Customers supply CWC when they pay for electric services received before the Company pays expenses incurred to provide that service. Utility customers are compensated for the CWC they provide by a reduction to the utility's rate base. A positive CWC requirement indicates that, in the aggregate, the shareholders provided the CWC. This means that, on average, the utility paid the expenses incurred to provide the electric services to its customers before those customers had to pay the company for the provision of these utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provided the CWC. This means that, on average, the customers paid for the utility's electric services before the utility paid the expenses that the utility incurred to provide those services.

Accounting Schedule 8, Cash Working Capital, identifies the amount of cash working capital to be reflected in KCPL's cost of service. Staff's CWC analysis results are reflected on the Rate Base Accounting Schedule 2 in the section "Add to Net Plant In Service." Staff's CWC analysis results used in the Schedule 2 section titled "Subtract From Net Plant" reflect the amounts of Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

Staff Expert/Witness: Matthew R. Young

H. Fuel Inventories

1. Coal Inventory

The amount Staff included in KCPL's rate base for coal inventory is based on the results obtained from Staff's production cost model ("fuel model"). Staff used its fuel model to determine the appropriate mix of generation and purchased power utilization to match the normalized native load for KCPL. In doing so, Staff obtained from the fuel model an annual amount of tons of coal burned by each coal-fired generation unit during the normalized updated test year. Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. Staff then multiplied this average daily burn by KCPL's recommended number of burn days of coal inventory for each generation unit and added an estimated level of basemat coal. Basemat coal is the bottom portion of the coal pile that is difficult to burn in the generating facilities because of the contamination of moisture, soil, clay, and other contaminants. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated. The aggregated amount was multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown in Rate Base – Accounting Schedule 2.

Staff Expert/Witness: Karen Lyons

2. Nuclear Inventory

To determine the amount to include in rate base for KCPL's nuclear fuel inventory, Staff used an 18-month average of the value of nuclear fuel that was contained in the fuel core of the Wolf Creek nuclear generating unit. Since the Wolf Creek unit is refueled every 18 months, this 18-month time period reflects the average nuclear fuel inventory value during a complete nuclear fuel usage cycle at Wolf Creek. This approach is consistent with the method used by KCPL to calculate the revenue requirement in this case. Staff's recommended level of nuclear fuel inventory for KCPL is shown on Schedule 2 of Staff's Accounting Schedules.

Staff Expert/Witness: Karen Lyons

3. Oil and Fuel Additive Inventories

Staff used 13-month averages to determine the inventory levels for oil, lime, limestone, ammonia, and powder activated carbon inventories as of June 30, 2016. Staff priced out the various inventories using the latest pricing or the actual monthly dollar levels of inventory. Use of 13-month average inventory levels is appropriate in that it reflects KCPL's actual experience for the entire 12-month update period ending June 30, 2016 by including a beginning inventory and an ending inventory. Using the test year ending 12 months ending December 31, 2015 as an example, a 13 month average would begin with January 1 and end with December 31. A 13-month average reflects the entire year by using the December 31 (January 1) beginning balance and including each subsequent month-ending balance through the end of the year

(December 31). Twelve month-ending balances from January 31 through December 31 do not accurately reflect the KCPL's actual experience because they ignore the impact of the period from January 1 through January 30. When inventory levels fluctuate from month-to-month, as they do with fuel stocks, a 13-month average is used to smooth out those levels. Staff's inventory levels for coal, nuclear, oil, limestone, and ammonia are shown in Rate Base – Accounting Schedule 2. Staff's approach is consistent with the method used by KCPL to calculate the revenue requirement in this case.

Staff Expert/Witness: Karen Lyons

I. Customer Deposits

Staff's recommended treatment of customer deposits is to deduct the most current customer deposit balance, as reflected in the Missouri jurisdictional total, from KCPL's rate base. Customer deposits are the funds required to be provided by certain customers taking electrical service from KCPL. These funds are deducted from KCPL's rate base because these funds are cost-free to KCPL. The amount reflected for customer deposits on Accounting Schedule 2, Rate Base, is a thirteen (13) month average for the period June 2015 to June 2016. The balance reflected on the Rate Base Accounting Schedule is the Missouri jurisdictional total for customer deposits. The thirteen (13) month average was used because the account balance fluctuated over that period. In addition to the amount deducted from rate base for customer deposits, an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903 (Accounting Schedule 10). Customers are paid interest for the use of the funds they provide to KCPL on a cost-free basis, and that interest expense is included as an expense in the revenue requirement calculation discussed in more detail in the "Customer Deposits - Interest Expense" section below. The Commission should base its awarded revenue requirement on Staff's recommended deduction on a thirteen (13) month average for the period June 2015 to June 2016 for Customer Deposit funds reflected in the Missouri jurisdictional total from KCPL's rate base.

Staff Expert/Witness: Michael Jason Taylor

J. Customer Advances

Staff's recommended treatment of customer advances is to deduct a 13-month average of account balances ending June 30, 2016, from KCPL's rate base, as the monthly account balances for KCPL did not exhibit a discernible upward or downward trend.

Customer advances are funds typically provided by construction developers to KCPL in order to ensure that KCPL builds electric infrastructure in areas that have potential for future development. These advances are also used by the utility to establish electric service for potential future customers without investing a substantial amount of money at the risk of the utility and its other customers. Unlike customer deposits, where KCPL receives these payments from respective customers on a cost-free basis without any future obligation to provide electrical service to those customers, customer advances are provided to KCPL from certain customers that obligate KCPL to provide future electrical infrastructure and service for those affected customers. Customer advances represent a recorded liability to recognize the obligation to eventually return the funds advanced by customers to KCPL. The infrastructure constructed with these funds is not financed with debt or equity and, thus, ratepayers should not be obligated to pay a return on these plant investments. Thus, customer advances are included in the rate base on Accounting Schedule 2 as a reduction, lowering the amount of overall investment that customers must supply as a return to the utility.

Staff Expert/Witness: Michael Jason Taylor

K. Iatan Construction Accounting Regulatory Assets

During the creation and execution of KCPL's Experimental Regulatory Plan for the construction of Iatan 2, which involved adding pollution control equipment to Iatan 1, as well as other investments, the Commission authorized KCPL to book certain costs into regulatory asset accounts for potential recovery in future general rate cases. Below is a table that identifies the Iatan generating units, the costs associated with that generating unit the Commission authorized KCPL book in a regulatory asset account, and the time period over which the costs were collected in the regulatory asset account:

Owner	Generating Unit	Expense Type	Accumulation Period
KCPL	Iatan 1 and	Depreciation, Carrying	May 1, 2009 – May 4,

	Common	Cost, No O&M	2011
KCPL	Iatan 2	Depreciation, Carrying Cost, O&M	August 26, 2010 – May 4, 2011

Pursuant to the Commission's Order of June 10, 2009, in Case No. ER-2009-0089, approving the 2009 Stipulation and Agreement, the Commission authorized KCPL to create a regulatory asset account for recording the depreciation and carrying costs for the Iatan Unit 1 AQCS[55] and Iatan common facilities appropriately recorded to electric plant-in-service, but the amount in that account was not included in KCPL's rate base in that case. Pursuant to the Commission's July 28, 2005 Report and Order approving the Stipulation and Agreement filed in Case No. EO-2005-0329, the Commission authorized KCPL to create a regulatory asset account for booking the depreciation, carrying costs, and other operating expenses and credits for Iatan Unit 2 subsequent to its fully operational and used for service date of August 26, 2010.

For purposes of inclusion in KCPL's rate base, Staff reflected the unamortized balances of these regulatory asset accounts as of June 30, 2016, the end of the test year update period the Commission ordered in its procedural schedule order in this case. Staff will update the balance of the regulatory assets through December 31, 2016, in its true-up of rate base.

The Iatan Unit 1 and Iatan facilities common regulatory assets, capturing construction accounting from May 1, 2009, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, is referred to by Staff as "Iatan 1 - Vintage 1." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized to expense over 26 years.

The Iatan Unit 1 and common regulatory asset, capturing construction accounting from January 1, 2011, through May 4, 2011 (the effective date of new rates in Case No. ER-2010-0355), is referred to by Staff as "Iatan 1 - Vintage 2." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized to expense over 24.3 years.

The Iatan Unit 2 regulatory asset, capturing construction accounting from August 26, 2010, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0355, is referred to by Staff as "Iatan 2 - Vintage 1." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and is amortized to expense over 47.7 years.

The Iatan Unit 2 regulatory asset, capturing construction accounting from January 1, 2011, through May 4, 2011, the effective date of rates in Case No. ER-2010-0355, is referred to

[55] Air quality control system.

by Staff as "Iatan 2 - Vintage 2." This regulatory asset is included in Staff's schedule labeled, "Rate Base – Schedule 2," and amortized to expense over 46 years.

The test year ending December 31, 2015, includes a full 12 months of amortization related to these regulatory assets; therefore, no adjustment to expense is necessary.

Staff Expert/Witness: Matthew R. Young

VI. Income Statement – Revenues

A. Rate Revenues

1. <u>Introduction</u>

This section will describe how Staff determined the level of KCPL Operating Revenues. The largest component of operating revenues results from the rates charged to KCPL's retail customers, therefore, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri retail electricity rates. Staff through its investigation has discovered some discrepancies between KCPL's and Staff's revenue calculations. Staff is investigating this further and will provide any relevant information in future testimony. An increase in the current rates KCPL charges its Missouri retail customers for electricity may be appropriate, if the overall cost of providing service to Missouri retail customers exceeds the operating revenues.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be corrected (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenue) prospectively. Operating Revenues are composed of Off-system Sales, Other Operating Revenue and Rate Revenue.

Rate Revenue – Test Year rate revenues consist solely of the revenues derived from KCPL's charges for providing electric service to its Missouri retail customers. KCPL's revenues are determined by taking each customer's usage and applying the appropriate tariffed rates. The appropriate rate varies based on different factors, including the time of the year (summer vs. winter), types of charges (demand, energy, etc.), and the customer's rate class.

Staff Expert/Witness: Michael L. Stahlman

2. <u>The Development of Rate Revenue</u>

Staff's recommended method for developing Rate Revenue is to determine annualized, normalized billing units and revenues by rate classes during the Test Year of January 1, 2015 through December 31, 2015, updated through June 30, 2016, for rate switchers and customer growth.

Staff's adjustments to KCPL's Missouri jurisdictional billing units and rate revenues are based upon information that is "known and measurable" through the end of the Update Period (June 30, 2016). The two major categories of revenue adjustments are known as "normalization" and "annualization." Normalizations address Test Year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect, e.g., events such as the Test Year weather. Annualizations are adjustments that re-state the Test Year results, updated through June 30, 2016, for rate switchers, customer growth, and new retail rates, as if conditions known at the end of the Test Year had existed through June 30, 2016.

Not all adjustments affect both billing units and rate revenue and not all rate classes are subject to every adjustment.

Staff Expert/Witness: Michael L. Stahlman

3. <u>Weather Normalization</u>

a. Weather Variables

Historical Data Used to Calculate Weather Variables – Each year's weather is unique; consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need to be adjusted to "normal" weather so that rates will be designed on the basis of normal weather rather than any anomalous weather which occurred in the test year. In the quantification of the relationship between test year weather and energy sales, Staff used weather observations for the test year of January 1, 2015, through December 31, 2015, from the Kansas City International Airport ("MCI") in Kansas City, Missouri.

As a measure of "normal" weather, Staff used a 30-year period of "climate normals" ("normals") published by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and Atmospheric Administration ("NOAA"). According to NOAA, a climate normal is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[56] To conform to the NOAA's three consecutive decades 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. Therefore, Staff bases its calculations on the time period of the most recent climate normals produced by NCDC.[57]

Although the definition of normal weather is relatively simple, the actual calculations may be more complicated. Inconsistencies and biases in the 30-year time series of daily temperature observations occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011.[58]

Staff verified the adjustments for anomalies in the MCI time series by direct communication with NCDC, and through Staff's own review of the daily observations. According to NCDC, the serially-complete monthly minimum and maximum temperature data sets have been adjusted to remove all inconsistencies and biases due to changes in the associated historical database. Furthermore, Staff reviewed NCDC's peer-reviewed, published paper[59] that explains the meteorological and statistical soundness of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies, and found it to be statistically sound.

Staff uses daily temperature observations to calculate normal weather values; however, NOAA's normals are monthly values. Staff adjusted the observed daily temperatures so that the monthly average temperatures calculated from these adjusted daily values are the same as the NCDC's serially-complete monthly 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.

[56] Retrieved on June 27, 2016, http://www ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals.

[57] Retrieved on June 27, 2016, http://www ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data.

[58] Arguez, A., I. Durre, S. Applequist, R. S. Vose, M. F. Squires, X. Yin, R. R. Heim, Jr., and T. W. Owen, 2012: NOAA's 1981-2010 U.S. Climate Normals: An Overview. Bulletin of the American Meteorological Society, 93, 1687-1697.

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

Weather Variables - Weather fluctuates greatly from day-to-day; therefore, the MCI temperature variables required to weather-normalize sales are the test year's actual temperatures and the 30-year normal two-day weighted daily mean temperatures. The day's daily mean temperature is generally defined as the simple average of the day's maximum daily temperature and minimum daily temperature. The daily, two-day weighted mean temperature is calculated using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight.[60]

The calculation was done because in the KCPL service area, the prior day's weather effects how electricity is used today. This is likely due to heat retention by the structures in the service area. For example, if today's temperature is mild, but yesterday's temperature was hot and the air conditioner was on, it is likely that the air conditioner will also be used today. Similarly, if yesterday's temperature was mild and air conditioning was not used, then if today's temperature is warmer, air conditioning may not be used until later in the day. Staff used the MCI daily, two-day weighted mean temperature data series to normalize both class usage and hourly net system loads.

Calculation of "Normal Weather" - Staff used a ranking method to calculate normal weather estimates of 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.

The ranking process 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. Staff's calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily normal temperatures because Staff calculated its normal daily temperatures based on the rankings of the actual temperatures of the test year, and the test year temperatures do not follow smooth patterns from day to day.

Staff Expert/Witness: Seoung Joun Won, PhD

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[60] To calculate the a given 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: $TWMT_D = (2/3)\ DMT_D + (1/3)\ DMT_{D-1}$.

b. Weather Normalization

For many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature increases, the demand for additional cooling, air conditioning, and fans increases customers' consumption of electricity. As the temperature falls, the demand for additional heating, including electric space heating, also increases customers' electricity consumption. Electric air conditioning and space heating is prevalent in KCPL's service territory; therefore, KCPL's electric load is linked and responds to daily changes in temperature.

Staff used the load data of the test year, January 1, 2015, through December 31, 2015, in its weather normalization process. February 2015 experienced temperatures colder than normal, and September 2015 experienced temperatures hotter than normal, resulting in electric energy usage above that which would have been expected under normal weather conditions. July 2015 through August 2015 and November 2015 through December 2015 experienced milder temperatures than normal, resulting in usage below that which would have been anticipated under normal conditions. Because the temperatures in Staff's test year deviated from normal, Staff performed a weather impact analysis.

Staff's model and methodology contain elements important in the class level weather normalization process such as 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 used by Staff witnesses Michael L. Stahlman and Michelle A. Bocklage in the normalization of revenues for the Residential ("RES"), Small General Service ("SGS"), Medium General Service ("MGS"), Large General Service ("LGS") and Large Power Service ("LPS") classes as explained in their direct testimony.

Staff Expert/Witness: Seoung Joun Won, PhD

c. 365-Days Adjustment to Usage

KCPL's customers' usage is measured, and rate revenue is collected over a period known as a revenue month, which is the interval of time over which KCPL reads customers' meters and generates invoices. Calendar months, which coincide with a standard calendar and begin on the first day of the month and end on the last day of the month, and revenue months, differ from one another because the periods they cover begin and end at different times. An invoice rendered for a given revenue month may charge for usage in portions of two calendar months. Revenue months take their names from the calendar month in which the customer's invoice is rendered. For example, assume a customer's meter was read and usage was determined on June 8 and then again on July 8; and that the invoice was sent to the customer on July 15. The revenue month for this invoice is July, even though 22 days of the usage measured for this invoice occurred from June 9 through June 30 and it contained only eight days of usage in July. Staff calculated a normalization adjustment to KCPL's kWh usage to reflect a calendar year's (365 days) worth of usage.

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 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 stated in kWh is referred to as 365-Days Adjustment.[61]

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 Adjustments for RES, SGS, MGS, and LGS were provided to Staff witness Michael L. Stahlman, who used the 365-Days Adjustment to adjust the revenues of the weather normalized class revenues months to the twelve months ended December 31, 2015. For 365-adjustments of LPS customers, please see the large customer section of Staff witness Michelle A. Bocklage's direct testimony.

Staff Expert/Witness: Seoung Joun Won, PhD

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

4. <u>The Effect of the Weather Normalization and 365-Days Revenue Adjustment on Rate Revenue for Weather Sensitive Classes</u>

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. For example, when the weather becomes warmer, the demand for cooling, air conditioning, and fans increases the customers' consumption of electricity. Conversely, the usage of electric space heating will increase electricity usage when the weather grows cold.

Additionally, calendar months and revenue months differ from one another because the periods they cover begin and end at different times. For example, calendar months coincide with the calendar, beginning on the first day of the month and ending on the last day of the month while revenue months, which can start and stop on days other than the beginning and end of a calendar month, can vary from customer to customer.

To calculate weather-normalized and 365-days adjusted revenue, Staff applied the rates that were effective for that month to weather normalized and 365-days adjusted usage. The weather-normalized and 365-days adjusted usage was calculated for the Residential Service ("RES"), Small General Service ("SGS"), Medium General Service ("MGS"), and Large General Service ("LGS") using normalized and annualized kWh factors provided by Staff witness Seoung Joun Won. For example, if the normalized and annualized kWh factor is 0.97 for the month of September in the RES rate class, then the total actual usage for that month and that rate class is decreased by 3%.

Staff adjusted actual billing determinants to equal the normalized and annualized monthly kWh using the relationship between actual average usage per customer and normalized and annualized average usage per customer. Staff also used the relationship between percentage of usage priced in the first rate block and the second rate block to distribute normalized and annualized monthly kWh to the rate blocks for the RES, SGS, MGS, and LGS classes. This calculation resulted in normalized usage by rate block, which was then converted to total normalized and annualized revenues by multiplying rate block usage by the appropriate rates. Staff's weather normalization revenue adjustment is equal to the difference between weather-normalized revenue and the Test Year revenue.

The weather normalization process assumes that weather has no effect on either the number of customers or on the fixed charges these customers currently pay. Weather variations only affect the energy usage of each existing customer and, thus, weather normalization only changes revenue directly related to usage.

Staff Expert/Witness: Michael L. Stahlman

5. <u>Customer Growth</u>

a. Customer Growth in Usage

Staff adjusted the usage and revenue through June 30, 2016, for customer growth, using the kWh information provided by Staff witness Matthew R. Young for all Missouri customers, to reflect the additional usage and rate revenues that would have occurred if the number of customers taking service at the end of June 30, 2016 had existed throughout the entire Test Year.[62] Staff separately included an adjustment for three customers who moved from the LP class during the test year into the LGS class.[63] Staff concluded that this adjustment was fitting since the average usage of these customers greatly differed from the average class usage.

Staff Expert/Witness: Michael L. Stahlman

b. Adjustments for Non-Missouri classes

Staff adjusted the Residential, SGS, MGS, and LGS classes' usage for KCPL's Kansas customers for weather both to provide normalized kWh and for the 365 days adjustment. These adjusted usages were provided to the Staff auditors for application to growth. Once Staff applied the growth adjustment, the final normalized and annualized usage was provided to Staff witness Seoung Joun Won for inclusion in his calculations of Net System Input ("NSI"), and to Staff witness Alan J. Bax for inclusion in his determination of jurisdictional allocations.

Staff Expert/Witness: Michael L. Stahlman

c. Customer Growth in Rate Revenue

Staff made customer growth adjustments to the test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue, which would have occurred if the number of customers taking service at the end of the update period (June 30, 2016) had existed throughout the entire test year. Staff calculated customer growth for the Residential, Small General Service,

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[62] When the kWh was applied to class energy blocks based on the percent of energy in each block, the revenue that was calculated was slightly higher than the revenue that Staff witness Matthew R. Young had previously calculated. Staff adjusted kWh and revenues for the RES, SGS, MGS, and LGS rate classes only.

[63] Response to Staff Data Request No. 0236.

Medium General Service, and Large General Service rate classes using customer levels as of June 30, 2016.

For this Direct Testimony filing, Staff updated all significant elements of revenue, expense, and rate base over the 12-month period ended December 31, 2015, test year level and for any known and measurable changes through June 30, 2016. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff employed the following method of computing the annualized level of increased revenue from customer growth at June 30, 2016. For each customer rate group, the customer level during each month of the test year is compared to the level as of June 30, 2016, and the monthly change in customer level is computed. This growth in customers is then multiplied by the weather-normalized revenue per customer experienced for that month of the test year.

Staff's approach assumes that the revenue pattern experienced in each month of the test year will recur on a weather-normalized basis, factored up (or down) in accordance with the growth (or decrease) in customer numbers at June 30, 2016.

The only retail customer rate group for which this approach is not taken is the Large Power Service customers. With respect to Large Power Service customers, energy consumption and revenue patterns vary significantly across this group of customers, making it necessary to examine the history of each customer on an individual basis, and to adjust the test year revenue level accordingly. Staff witness Michelle A. Bocklage addresses the Large Power Service revenue annualization. Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, General Service, and Large Power Service customers in order to provide the annualized level as of June 30, 2016. The retail customer growth adjustment other than Large Power Service is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-2.6.

Staff Expert/Witness: Matthew R. Young

B. Large Power Service ("LPS") Adjustments

Staff determined annualized and normalized test year usage and revenues for the LPS class, adjusted for rate switchers, on an individual customer basis from January 1, 2015 through December 31, 2015. There were 74 customers in the LPS rate class at the beginning of the test year. Four customers left the LPS rate class and two new customers were added to the LPS rate class. This resulted in Staff analyzing the usage history of 68 LPS rate class customers with usage for the entire test year period.

Each LPS customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor; therefore, the class sales and revenues were annualized on an individual customer account basis. LPS class revenues were also annualized for major growth or decline in kWh sales and rate revenues due to the entrance of the two new customers, the four existing customers leaving, and load growth or decline of specific existing customers active at the end of December 2015.

Staff Expert/Witness: Michelle A. Bocklage

C. Transmission Revenue-FERC Account 456

KCPL books transmission revenue to FERC Account 456. KCPL receives revenues from SPP on the following SPP tariff schedules:

- Schedule 2: Revenues related to reactive supply for generators connected to the transmission system
- Schedule 7: Revenues related to firm point-to-point transmission
- Schedule 8: Revenues related to non-firm point-to-point transmission
- Schedule 9: Revenue related to network integrated transmission
- Schedule 11: Revenues related to the base plan transmission upgrades

Although KCPL receives revenues from SPP based on all of the schedules listed above, a significant percentage of the transmission revenues received from SPP are from firm and non-firm point-to-point transmission and base plan transmission activities. In its updated direct case, KCPL made an adjustment to reduce transmission revenue for the difference in KCPL's authorized FERC ROE of 11.1% and KCPL's proposed ROE in this case of 9.9%. KCPL refers to this adjustment as the wholesale revenue adjustment. Staff's recommendation for this adjustment is addressed below.

Staff analyzed KCPL's transmission revenue for the period of 2009 through July 2016, and reviewed KCPL's proposed wholesale revenue adjustment. Staff included an annualized level of transmission revenues based on the 12 month period ending June 30, 2016 and is reflected on Schedule 10 of Staff's Accounting Schedules, Adjustment Rev-24.1.

During its analysis of transmission revenue, Staff compared KCPL's historical transmission revenues to its transmission expense. KCPL's transmission revenue for the 12-month period ended December 31, 2015 ** __________ ** since 2009. The following chart reflects KCPL's historical transmission expense and revenues for the period of 2009-2015:

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**

As mentioned above, Staff reviewed KCPL's adjustment to reduce transmission revenues for the difference in KCPL's authorized FERC ROE of 11.1% and KCPL's proposed ROE in this case of 9.9%. KCPL received the transmission revenues from SPP for point-to-point and base plan upgrades. The wholesale transmission revenue adjustment is calculated using the Annual Transmission Revenue Requirement (ATRR) using KCPL's authorized FERC ROE of 11.1%, not the 9.9% equity rate of return. The ATTR is used by SPP to allocate revenues and expenses to all transmission owners and transmission customers of SPP. The transmission owners receive allocated revenues based on the ATTR, and the transmission customers are charged for allocated costs based on the ATTR. The ATTR includes incentives such as allowing CWIP in the revenue requirement, ROE adders, etc. KCPL's authorized FERC ROE of 11.1% includes a base ROE of

10.6% and a ROE adder of 50 basis points for being a member of a regional transmission organization (RTO).

Other SPP transmission owners submit the ATTR that may include the previously discussed incentives. KCPL will then receive its allocated share of the transmission costs that include incentives. KCPL's participation in SPP encompasses both the financial impacts of KCPL's ownership of transmission assets and the financial impacts of the use of other SPP members' transmission assets. As discussed in the Transmission Expense section of this report, the financial impact of KCPL's use of other SPP members' transmission assets have resulted in a ** ____________ ** in transmission expense since 2009 and as seen in the table above, the financial impact of KCPL's ownership of transmission assets resulted in a ** ____________ ** in transmission revenue since 2009. Staff did not make an adjustment to reduce transmission revenues for the difference in KCPL's authorized FERC ROE of 11.1% and its KCPL's proposed ROE of 9.9% and instead reflected the financial impact of both unadjusted transmission revenue and transmission expense. It is Staff's position that KCPL's participation in SPP encompasses both the financial impacts of KCPL's ownership of transmission assets and the financial impacts of the use of other SPP members' transmission assets. Consequently, KCPL customers are entitled to all transmission revenues that offset a part of the significant increases in transmission expense.

Staff Expert/Witness: Karen Lyons

D. Ancillary Services

Ancillary services, also known as operating reserves, include Regulation-up, Regulation-down, Spinning Reserve, and Supplemental Reserve services. These services support the transmission of capacity and energy while maintaining the reliability of the transmission system. Regulation–up and Regulation-down maintain the balance between the generation and the load. Spinning and Supplemental Reserve require that an energy resource, such as a power plant, must be available in the event of an outage. Prior to March 1, 2014, KCPL was part of an Energy Imbalance Service market ("EIS") and self-designated ancillary services. On March 1, 2014, the SPP Integrated Marketplace began replacing the previous EIS market. Consequently, KCPL now purchases ancillary service from SPP and sells the services to SPP.

Staff reflected ancillary services for the 12 months ending June 30, 2016, the update period in this case. Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment Rev-11.4. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

E. Market to Market Sales

In SPP's Integrated Market, KCPL has the opportunity to purchase energy from SPP and subsequently sell energy to another energy market. KCPL monitors the price differences in each real time market and if it is determined that a transaction will be profitable, the purchase and subsequent sale is made.

Staff reflected KCPL's market-to-market transactions for the 12 months ending June 30, 2016, the update period in this case. Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment Rev-11.5. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

F. Transmission Congestion Rights

Transmission Congestion Rights ("TCR") are an energy financial instrument that entitles the holder to be compensated or charged for congestion in the SPP Integrated Market between two settlement locations.[64] When transmission congestion occurs, KCPL incurs additional charges from SPP for moving energy from generation to load. KCPL, as a transmission owner, is allocated TCRs to hedge the actual transmission congestion charges incurred to serve its native load. A transmission owner in SPP is an owner of physical assets within a given service territory

TCRs may result in a source of revenue or a charge from SPP. Based on discussions with KCPL personnel and responses to Staff data requests, KCPL sells more power into SPP than it purchases from SPP, a situation commonly referred to as "long-in-the-market." In other words, in total, KCPL produces more electrical energy for the SPP market than it takes from this market. Consequently, TCRs are a source of revenue.

[64] SPP Tariff 105.

Staff reflected TCRs for the 12 months ending June 30, 2016, the update period in this case. Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment Rev-11.2. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

G. Revenue Neutral Uplift

The revenue neutral uplift charges are imbalances between revenues and disbursements that are distributed by SPP to SPP market participants as either a charge or a credit. As a not-for-profit organization, SPP must remain revenue neutral. Consequently, SPP will charge or credit KCPL for the revenue neutral uplift charge. The charge consists of miscellaneous charges or credits that SPP has no other method of distributing to SPP market participants.

Staff reflected revenue neutral uplift charges for the 12 months ending June 30, 2016, the update period in this case. Staff's adjustment is identified on Schedule 9 of Staff's Accounting Schedules, Adjustment Rev-11.3. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

H. Off-System Sales

1. <u>FERC Account 447-Sales for Resale</u>

FERC Account 447, Sales for Resale, includes three sources of revenue for KCPL:

- firm off-system sales;
- non-firm off-system sales; and
- FERC wholesale sales

Staff Expert/Witness: Karen Lyons

2. <u>Firm Off-System Sales</u>

During the test year ended December 31, 2015 updated through June 30, 2016, KCPL contracted to sell firm off-system power to the following customers:

1. City of Chanute, Kansas ("Chanute"); and

2. City of Eudora, Kansas ("Eudora")

3. Kansas Municipal Energy Agency ("KMEA")

Under their respective contracts, these customers paid both a demand charge for the megawatt capacity commitment from KCPL and an energy charge for the cost of delivered energy. In addition, KCPL has an agreement with GMO to sell a specified amount of capacity at GMO's option. As a result, Staff annualized KCPL's firm demand and energy sales based solely on the capacity contracts in effect with Chanute, Eudora and KMEA (plus the capacity sales option with GMO as of the update period ended June 30, 2016.

Staff has reviewed KCPL's firm off-system sales levels and adjusted test year levels to reflect the levels for the 12-month update period ended June 30, 2016. Adjustments Rev-8.1 and Rev-10.1 reflect the adjustments to firm off-system sales levels.

Staff Expert/Witness: Karen Lyons

3. <u>Non-Firm Off-System Sales</u>

For purposes of discussing revenue requirement calculations, non-firm off-system sales are sales of electricity made at times when a utility's generation output exceeds the load requirements of its native load customers (rate tariff customers) and firm sale customers. KCPL must first meet its firm sales loads, and if it has excess electricity to sell, it will make off-system sales. The difference between the revenue received for selling the excess generation and the cost of the fuel used to produce the energy sold are referred to as off-system sales margin ("OSSM"). Off-system sales are made at market-based rates. Off-system sales are made through KCPL's generation or through electricity purchased from other utilities.

Since March 2014, KCPL has taken part in the SPP integrated market. KCPL offers its generating units for dispatch through the SPP, and the SPP dispatches KCPL and all other SPP generating owners' generation to meet the load requirements of the entire SPP region. For purposes of discussing revenue requirement calculations, once all firm commitments are met (native load), any excess generation is available to sell through the market on a non-firm basis—off-system sales. Off-system sales generated through the fuel model are reflected in Staff's Accounting Schedule 10, Adjustments Rev 11.1.

Staff Expert/Witness: Karen Lyons

4. FERC Wholesale Sales

FERC wholesale customers are municipalities that buy electricity under a firm power tariff regulated by the FERC. Since the wholesale customers are treated as if they were located in another jurisdiction, none of the revenues from these customers are included in the Missouri utility's regulated operations. Staff allocates to the Missouri utility the plant-in-service, accumulated depreciation reserves, revenues, fuel and purchased-power costs, and maintenance costs required to serve Missouri customers using demand and energy allocation factors developed by Staff witness Alan J. Bax. The FERC jurisdictional loads are not included in the demand and energy allocators developed for the Missouri jurisdiction.

Staff Expert/Witness: Karen Lyons

I. Excess Off-System Sales Margin Regulatory Liability

Pursuant to KCPL's Regulatory Plan, KCPL agreed that off-system energy and capacity sales revenues, and related costs, will continue to be treated "above the line" for ratemaking purposes over the course of the Regulatory Plan. KCPL also agreed that it would not propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case during the life of the Regulatory Plan.

In its first rate case after the Commission approved the Regulatory Plan, Case No. ER-2006-0314, the Commission determined that, in setting KCPL's rates, the amount included in KCPL's revenue requirement for off-system sales should be the 25th percentile of non-firm off-system sales margin as projected in that proceeding, that KCPL book all amounts above the 25th percentile as a regulatory liability, but no corresponding regulatory asset would be booked should sales fail to meet the 25th percentile. This Order established the 2006 rate case tracker for off-system sales. The Commission ordered a continuation of this method of accounting for off-system sales in each of KCPL's three subsequent general rate cases, Case Nos. ER-2007-0291, ER-2009-0089 and ER-2010-0355.

In the *Non-Unanimous Stipulation and Agreement* the Commission approved in Case No. ER-2009-0089, the parties agreed to the final dollar amount for the 2006 and 2007 rate case trackers. The parties also agreed to set the 2009 rate case tracker off-system sales baseline at $30,000,000:

> <u>Off-System Sales ("OSS") Margins—Excess Over 25th Percentile for 2007 and 2008</u>
>
> The Signatory Parties agree that the $1,082,974 (Missouri jurisdictional) excess of 2007 OSS margins over the amount included in rates in Case No. ER-2006-0314 and the $2,947,332 (Missouri jurisdictional) excess of 2008 OSS margins over the amount included in rates in Case No. ER-2007-0291, together with interest (Missouri jurisdictional), will be deferred in a regulatory liability account and amortized over ten years beginning with the date new rates become effective in this rate case, with one year's amortization included in cost of service in this case. The unamortized balance will not be included in rate base.
>
> * * *
>
> <u>Off-System Sales Tracker</u>
>
> KCP&L's OSS margins at the 25th percentile shall be set at $30 million, and shall be used for tracking purposes. Such tracker will reflect a pro-ration, on a monthly basis, of this amount for any partial years consistent with the percent of actual OSS realized in each month of 2008. All OSS margins will be tracked against the $30 million baseline. The Signatory Parties reserve the right to assert a position regarding the appropriate definition of OSS in the Company's next general rate case.

Page 141 of the Commission *Report and Order* in KCPL Case No. ER-2010-0355, issued April 12, 2011, states, "KCP&L's rates shall be set at the 40th percentile of non-firm off-system sales margin as projected by KCP&L, as listed in KCP&L witness Schnitzer's Direct Testimony. Margins above the 40th percentile shall be returned to ratepayers in a subsequent rate case or rate cases." KCPL did not realize any excess margins over the 40th percentile from the 2010 rate case and, thus, made no related adjustments to its regulatory liability.

Staff has calculated the amount of KCPL's amortization and interest related to this regulatory liability from the 2006, 2007, and 2009 rate cases and reflected the appropriate amount in Adjustment Rev-4.1.

Staff Expert/Witness: Karen Lyons

J. SO^2 Emissions Allowances

1. Deferred Sales from SO^2 Emissions Allowances

Since KCPL receives more SO^2 emission allowances ("SO2 allowances") from the U.S. Environmental Protection Agency ("EPA") than it requires for its own coal-burning operations, it may sell all or part of these surplus allowances. Under the FERC Uniform System of Accounts ("USOA"), proceeds from the sales of surplus SO^2 emissions allowances are recorded in FERC Account 254, the USOA regulatory liabilities account. For ratemaking purposes, amounts recorded as regulatory liabilities reduce a utility's rate base; i.e., the net amount in FERC Account 254, after any appropriate adjustments, is an offset to rate base.

Staff included in its direct case the balance of Account 254 on June 30, 2016 (the end of the update period in this case), as an offset to the rate base calculation found on Staff Accounting Schedule 2 filed with Staff's direct case. This approach is consistent with the treatment given this item in the last six KCPL rate cases: Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355, ER-2012-0174 and ER-2014-0370. Staff has reflected the amortization associated with this regulatory liability in Adjustment E-30.1. Treating these SO^2 emissions allowances in this manner acknowledges that, through rates, KCPL's customers have paid for KCPL's production facilities that create these SO^2 emissions allowances, which KCPL is able to sell to other entities for profit.

Staff Expert/Witness: Cary G. Featherstone

K. Miscellaneous Revenues

1. Late Payment Revenue (Forfeited Discount)

KCPL charges a late payment fee to customers who fail to pay bills in a timely manner. Staff annualized late payment fee revenues by using the ratio of late payment fees to Missouri total retail sales, both net of gross receipt taxes ("GRT"), from June 30, 2015 to June 30, 2016 because the data from this time period represents the most recent and most relevant information. This ratio was multiplied by the Staff's annualized revenue, resulting in an annualized level of late payment fees. This is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-15.2.

Staff Expert/Witness: Matthew R. Young

L. Other Revenue Accounts

Staff reviewed the amounts KCPL included in its cost of service calculation for "Other Revenues," which include rent from electric property, miscellaneous service revenues and temporary installation profit. Staff concluded the test year amounts for Other Revenues appeared to be reasonable and representative of an annualized level of revenue for each respective category and, therefore, do not require adjustment. However, Staff will apply its own allocation factors to those amounts that are common to other KCPL's operational jurisdictions. Staff will examine these revenue accounts again during its True-Up audit through December 31, 2016.

Staff Expert/Witness: Matthew R. Young

M. Removal of Gross Receipts Taxes from Test Year Revenues

The amounts received from customer payments and recorded as revenues during the test year include Gross Receipts Taxes ("GRT"). GRTs are imposed by a taxing authority for which KCPL is obligated to charge customers on their utility bills. After KCPL collects these taxes from its customers, it periodically remits these amounts to the appropriate taxing authority. In this regard, to accurately account for KCPL's actual test year retail revenues, it is both necessary to remove GRT from the amounts recorded as revenues during the test year and remove the corresponding remittances to the taxing authority as a charge to expenses. As a result, GRT should have no impact on KCPL's final revenue requirement amount. Staff's adjustments remove GRT from test year revenues and expenses and are reflected in Staff's Accounting Schedule 9, Rev-3.1, Rev-15.1 and E-261.1.

Staff Expert/Witness: Matthew R. Young

VII. Income Statement – Expenses

A. Fuel and Purchased Power Overview

KCPL has 4,360 megawatts of total generating capacity consisting of nuclear, coal-fired, natural gas, oil-fired generating units, and wind generation[65]. KCPL's generation capacity is made up of the following types of generation based on calendar year 2015 operating results:

[65] Staff Data Request No. 0057, Case No. ER-2016-0285.

Generation Capacity by Fuel Type	2015 Megawatts	Percentage of Generation Capacity (MW) by Fuel Type	2015 Percentage of MWHs Generated by Fuel Type
Coal	2,584 MWs	59.3%	80%
Nuclear	549 MWs	12.6%	16%
Natural Gas	780 MWs	17.9%	Less than 1%
Oil	401 MWs	9.2%	Less than 1%
Wind	46 MWs	1%	2%
Total	4360 MWs	100%	100%

Source: 2015 Shareholder Report- pages 8 and 23.

While KCPL's coal-fired generating units make up 59% of its total generating fleet, those units produce 80% of total system load requirements. Nuclear generating capacity makes up 12% of total KCPL capacity, but it produces 17% of total generation. Natural gas capacity makes up 18% of total capacity this fuel type makes up less than 1% of KCPL's total generation based on 2015 actual megawatt hours of generation.

continued on next page

2013-2015 KCPL Actual Generation (MMBTu)						
Generation	2015 Actual MMBTU	%	2014 Actual MMBTU	%	2013 Actual MMBTU	%
Coal	** ________ **	76.94%	** ________ **	79.21%	** ________ **	82.50%
Nuclear	** ________ **	21.89%	** ________ **	19.81%	** ________ **	16.36%
Natural Gas	** ________ **	.87%	** ________ **	.73%	** ________ **	.92%
Oil	** ____ **	.29%	** ____ **	.25%	** ____ **	.22%
Total	** ________ **	100%	** ________ **	100%	** ________ **	100%

Based on the actual 2015 generation by fuel type in MMBTu's, coal and nuclear make up 99% of total generation, with oil and natural gas making 1% of generation.

Staff Expert/Witness: Karen Lyons

B. Fuel and Purchased Power Expense

Staff estimates KCPL's variable fuel and purchased power expense to be $212,046,308 for a twelve month period ending June 30, 2016.

Staff uses the PLEXOS production cost model to perform an hour-by-hour chronological simulation of a utility's generation, power purchases, and power sales. Staff uses this model to determine the annual variable cost of fuel, net purchased power cost, and fuel consumption. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense.

Staff used market prices in its fuel model dispatch to simulate KCPL's operations in the Southwest Power Pool's Integrated Marketplace. Within the PLEXOS model, the price for energy in the Integrated Marketplace dictates the dispatch of KCPL generation resources and the amount of energy sold by KCPL.

The model operates in a chronological fashion, meeting each hour's energy demand before moving to the next hour. It will schedule generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operational constraints. This model simulates the way a utility should dispatch its generating units and purchase power in order to meet the net system load in a least cost manner.

Staff calculated the following inputs for use in the model: fuel prices, firm purchased power contract specifications, hourly net system input, unit capacity, and unit planned and forced outages. Staff relied on KCPL's responses to data requests and data KCPL supplied to comply with 4 CSR 240-3.190 for the characteristics of each generating unit; for example: unit heat rate, primary fuel type, ramp rates, startup costs, and fixed operating and maintenance expense. Information from KCPL's firm wholesale loads and firm purchased power contracts and prices are also inputs to the model.

Staff Expert/Witness: Charles T. Poston, PE

1. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence and variable in duration. In particular, forced outages are unplanned and can happen at any time. In order to capture this variability, average yearly planned outage durations and forced outage rates were calculated for KCPL generating units. The average values for each generating unit were based on seven years of data, when available. The outage information was taken from responses to Staff data requests and from information supplied by KCPL to comply with 4 CSR 240-3.190.

Staff Expert/Witness: Charles T. Poston, PE

2. Contract Prices and Energy

Utilities may enter into contracts for a specific amount of energy (megawatts or "MW") and/or a maximum amount of hourly energy (megawatt-hours or "MWh"). Prices for the energy from these contracts are based on either a fixed contract price or the generating costs of providing the energy. The contracts relevant to this case are the Cimmaron II, Spearville 3, Slate

Creek, Waverly, and Osborn wind power contracts and the Central Nebraska Public Power and Irrigation District ("CNPPID") hydro power contract.

For the Cimmaron II, Spearville 3, and CNPPID contracts, Staff developed hourly energy production by averaging the historic hourly generation records that were supplied by KCPL. In the case of the Slate Creek and Waverly contracts, less than one year of actual production statistics was available. As a result, Staff adopted the estimated generation levels used by KCPL. The Osborn facility has been excluded from Staff's calculations for fuel and purchased power costs, because as of June 30, 2016, the Osborn wind farm was not yet supplying energy to KCPL. Energy prices ($/MWh) were obtained from the wind and hydro power contracts provided by KCPL.

Staff Expert/Witness: Charles T. Poston, PE

3. Fixed Costs

Fuel and purchased power costs that do not vary directly with fuel burned were not included in Staff's fuel model, but were determined separately. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as "fuel adders." These types of costs include non-wage fuel handling, dust suppressant, and freeze proofing coal for transportation from the mines to power plants. The non-variable purchased power costs not included in Staff's fuel model are commonly referred to as "capacity charges" or "demand charges" and are annualized separately from purchased power energy costs.

Staff Expert/Witness: Karen Lyons

4. Fixed Adders

The costs of fuel adders are determined separately and are added to the level of fuel expense determined by the model to determine overall fuel expense. Costs added to coal expense include unit train lease payments and unit train rail car maintenance costs. Fuel adders for natural gas include transportation charges and hedging costs. A significant percentage of natural gas transportation charges is fixed and under contract. Other fuel adder expenses incurred by KCPL include ammonia, lime, limestone, molten sulfur, and powder activated carbon ("PAC").

For natural gas fixed transportation costs and additives such as limestone and ammonia, Staff used the actual expenses for the 12-months ending June 30, 2016. Staff's adjustments are identified on Schedule 10 of Staff's Accounting Schedules, Adjustments E-7.3, E-12.1, E-12.2, E-13.1, E-102.1, and E-100.1. Staff will re-examine these expenses at the time of Staff's true-up, and update any costs as necessary.

Staff Expert/Witness: Karen Lyons

5. Purchased Power – Energy

Staff Adjustment E-115.1 annualizes purchased power energy charges based on Staff's fuel model results. These purchased power energy charges represent the energy KCPL purchases on the spot market and through contracts to meet the system load requirements of its retail electric customers. Staff witness Erin L. Maloney of the Engineering Analysis Section of the Operational Analysis Department is responsible for determining Staff's recommended price of purchased power and provides the results to Staff witness Charles T. Poston of the same Department, who includes the price as an input into Staff's fuel model.

Staff Expert/Witness: Karen Lyons

6. Purchased Power – Capacity Charges

Capacity charges, commonly referred to as "demand charges," represent fixed amounts that KCPL either pays for the "right" to purchase power, also known as capacity purchases, or is paid by another entity for the "right" to purchase power from KCPL. In the case of purchased power, the selling entity reserves generating capacity for KCPL to purchase when the electricity is needed under terms of the purchased power agreements. KCPL contracts this power with various entities and pays a fixed component for the reserve capacity and an energy component for any energy consumed. Generally, there is also an amount for operational and maintenance costs charged for the usage of energy. The fixed component is paid by KCPL as a demand charge, generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase the reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

The demand charges paid to KCPL by other generating entities, giving those entities the "right" to purchased power from KCPL, are known as capacity sales. The demand charges for capacity sales are addressed in the revenue portion of this Cost of Service Report.

Staff annualizes purchased power demand charges based on existing capacity contracts currently in effect. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Upon review of KCPL's capacity contracts, Staff determined that KCPL incurred costs for one contract during the test year and the contract ended before the update period of June 30, 2016. Since the contract was not renewed, Staff's adjustment E-116.1 eliminates the costs KCPL incurred during the test year.

Staff Expert/Witness: Karen Lyons

7. Border Customers

Border customers are customers who are in the service territory of one utility to which the customer will pay its bill, but are physically served by another utility's power lines. In other words, there are KCPL customers currently being served by another utility's power and customers of other utilities that are being served by KCPL's power. When KCPL customers are served by another utility, KCPL must pay the utility for the costs to serve KCPL's customers. The energy supplied by another utility for KCPL's customers is included in Staff's fuel model as a reduction to the net system input ("NSI") and the revenues for KCPL customers that are served by another utility are included in Staff's retail revenue and included in KCPL's cost of service. When another utility's customers are served by KCPL, the utility must reimburse KCPL for the cost of serving those customers. The energy supplied by KCPL is included in Staff's fuel model and the related fuel costs are included in KCPL's cost of service.

To ensure that all border customer costs and revenues are included in KCPL's cost of service, an additional adjustment must be made to include (1) the payment KCPL makes to reimburse other utilities for the costs to serve KCPL's customers – purchased power, and (2) the payment KCPL receives from other utilities for the costs to serve those utilities' customers -- sales.

Staff reflected KCPL border customers that includes purchased power and sales for the cut-off period, twelve months ending June 30, 2016. Staff's adjustment for KCPL border customers is reflected on Schedule 10 of Staff's Accounting Schedules, Adjustment E-115.1.

Staff Expert/Witness: Karen Lyons

8. Variable Costs

a. Fuel Prices

Staff computed fuel expense using prices and quantities actually incurred by KCPL as of June 30, 2016. Staff included fuel prices for nuclear, coal, natural gas, and oil, including transportation charges in the fuel USOA accounts 501 (coal), 518 (nuclear), and 547 (natural gas).

Staff Expert/Witness: Karen Lyons

b. Coal Prices

Staff determined coal prices by generation facility based on a review and analysis of KCPL's coal purchase (supply) and coal transportation (freight) contracts. Staff's recommended coal prices reflect KCPL's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect on June 30, 2016.

Staff Expert/Witness: Karen Lyons

c. Natural Gas Prices

As an input to its production cost model, Staff used twelve (12) monthly natural gas prices calculated using 12-month weighted averages of KCPL's actual commodity cost of natural gas through the end of the known and measurable period of June 30, 2016. KCPL's natural gas fixed transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Karen Lyons

d. Nuclear Fuel Prices

KCPL owns 47% of Wolf Creek. KCPL's 47% ownership interest in Wolf Creek entitles it to 549 megawatts[66] of the plant's capacity. In determining its nuclear fuel price, Staff relied upon KCPL's monthly Report 25 - the Fuel Report. Beginning in May 2014 the monthly nuclear fuel price decreased and, based on discussions with KCPL personnel, the decrease in price is attributable to the discontinuance of the nuclear waste disposal fee in May 2014. Staff's proposed nuclear fuel price is based on the most current fuel price as of June 30, 2016.

Staff Expert/Witness: Karen Lyons

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[66] KCPL response to Staff Data Request No. 0057 in Case No. ER-2016-0285.

e. Oil Prices

Staff used the actual cost KCPL paid for its most recent fuel oil purchases to determine variable fuel oil expense. KCPL burns fuel oil mainly as a start-up fuel for the coal-fired generating units or, in some instances, for flame stabilization. Oil is a primary fuel source at KCPL's Northeast units, which see very limited run time. As a result, KCPL purchases fuel oil infrequently. Historically, the limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because KCPL does not make purchases during the majority of the year. For its direct filed case, Staff recommends KCPL's most recent fuel oil purchase prices as of June 30, 2016, to input into the fuel model for determining KCPL's variable fuel and purchased power expense on a going forward basis.

Staff Expert/Witness: Karen Lyons

9. <u>Purchased Power Prices</u>

Staff analyzed hourly Southwest Power Pool Integrated Market Day Ahead market prices ("market prices") from the beginning of market operations on March 3, 2014 to the end of July 2016. Since the onset of the two-day markets in Missouri, Staff has used a three-year peak and off-peak average of market prices (when data is available) to adjust for extreme price points caused by anything from weather, new market operation, hurricanes, economic down turns, and flooding. Staff calculated the average monthly prices as well as peak and off-peak prices for each month in this period. Early market prices saw extreme highs and huge fluctuations with prices steadily dropping through 2015 and 2016. The three year average of market prices is much higher than the average market prices in 2015 and 2016. For Staff's direct case, the Company's market prices, with an adjustment to reflect the 2016 market downturn, have been adopted as a reasonable normalized forecast of market prices. Staff will continue to review market prices through the true-up period and will update prices as necessary

Staff Expert/Witness: Erin L. Maloney, PE

10. <u>Normalized Net System Input</u>

Hourly net system input is the hourly electric supply necessary to meet the hourly energy demands of a utility's customers; the input is net of (i.e., does not include) station use, which is the electricity requirement of the utility's generating plants.

Due to the presence of significant air conditioning and electric space heating in KCPL's service territory, the magnitude and shape of KCPL's net system input is directly related to daily temperatures. To normalize net system input, Staff used actual and normal daily temperatures provided by Staff witness Seoung Joun Won in its analysis. The actual daily temperatures for the test year, the twelve months ending December 31, 2015, differed from normal daily temperatures. Therefore, to reflect normal weather, daily peak and average net system loads were each adjusted independently, but using the same methodology.

Daily average load is the summation of the hourly load for the day divided by twenty-four hours. Daily peak is the maximum hourly load for the day. Staff uses separate regression models to estimate both (1) a base component, which is allowed to fluctuate across time as non-weather factors, and (2) a weather-sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. Independent regression models are necessary because daily average loads respond differently to weather than peak loads. The models' regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added, respectively, to the actual average and to the peak loads of each day. In order to allocate the weather-normalized daily peak and average loads to each individual hour of the year, Staff begins with the actual hourly loads for the year being normalized. A unitized load curve[67] is calculated for each day as a function of the actual peak and average loads for that day. Staff uses the corresponding weather-normalized daily peak and average loads, along with the unitized load curves, to calculate weather-normalized hourly loads for each hour of the year.

This process includes many checks and balances, which are included in Staff's direct workpapers. The Staff analyst is required to examine the data at several points in the process, to

[67] A unitized load curve is a set of 24 hourly loads of a given day calculated by subtracting the average daily load from each hourly load, then dividing by the difference between the peak and the average so that the average of the calculated hourly loads is 0 and the peak is 1.

further ensure accuracy. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[68]

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

Staff applies a factor to each hour of the weather-normalized loads to produce an annual sum of the hourly net-system loads that equals the usage, plus losses, consistent with normalized revenues. Once completed, the hourly normalized system loads were used in developing Staff's fuel and purchased power expense as explained in Staff witness Charles T. Poston's, direct testimony. Staff witness Alan J. Bax also used the annual requirement of the net system load in developing Staff's jurisdictional energy allocator, as explained in his testimony.

Staff Expert/Witness: Seoung Joun Won, PhD

11. System Energy Losses

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

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

NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses

NSI, Retail Sales, Wholesale Sales, and Company Use are known quantities; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – (Retail Sales + Wholesale Sales + Company Use)

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

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

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

NSI is also equal to the sum of KCPL's net generation and net interchange. Net interchange is the difference between off-system purchases and off-system sales. Net generation is the total energy output of each generating plant minus the energy consumed internally to enable the production of electricity at each plant. The output of each generating plant is monitored and metered continuously. The net of off-system purchases and off-system sales (Net Interchange) is also similarly monitored.

Staff has calculated a system energy loss factor of 0.0589 based on an analysis of data experienced during calendar year 2015, the test year of this case. This system energy loss factor will be used by Staff witness Seoung Joun Won in the development of hourly loads that are included in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

12. <u>Loss Study as it Applies to the Fuel Adjustment Clause</u>

KCPL supplied Staff with a Loss Study in its response to Staff Data Request No. 172 in its last rate case (Case No. ER-2014-0370). This loss study is an analysis based on data collected during calendar year 2013. Therefore, KCPL is in compliance with the rule requirement of 4 CSR 240-20.090(9)[69] that a current loss study be provided in conjunction with a request to continue a Rate Adjustment Mechanism, such as KCPL's request to continue its FAC in the current case.

Utilizing information included in the aforementioned loss study, Staff has calculated the following voltage adjustment factors:

Transmission – 1.0195

Primary – 1.0451

Secondary – 1.0707

[69] 4 CSR 240-20.090(9) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

These voltage adjustment factors account for the energy losses experienced in the delivery of electricity from the generation level to the retail customer (secondary level). These factors will be utilized in Staff's determination of Fuel Adjustment Rates ("FAR"), applicable to the individual voltage service classification of a particular customer in the corresponding FAC tariff, if the Commission authorizes KCPL to continue its FAC tariff.

Staff Expert/Witness: Alan J. Bax

13. <u>Surface Transportation Board Reparation Amortization</u>

On October 12, 2005, KCPL filed a rate complaint case with the Surface Transportation Board ("STB") against Union Pacific Railroad ("UPRR") alleging UPRR's charges to transport coal from Wyoming's Powder River Basin ("PRB") to KCPL's Montrose plant in Missouri were excessive.

On May 15, 2008, the STB ruled in favor of KCPL and ordered UPRR to reduce its rates to KCPL and pay KCPL reparations for prior overcharges. The STB estimated the value of the rate reductions and reparations to be $30 million.

During the period between the STB rate complaint case and the final decision, KCPL filed two general rate cases before this Commission, Case No. ER-2006-0314 and Case No. ER-2007-0291. In Case No. ER-2006-0314, Staff and KCPL, by agreement, treated KCPL's actual STB litigation costs as a regulatory asset amortized to expense over five (5) years beginning in January 2007. Staff and KCPL also agreed that proceeds from the complaint were first to be applied as an offset to any existing balance of the STB case costs in the regulatory asset, with the remainder being applied to offset fuel costs as determined in future proceedings. The Commission in its Report and Order in that case observed that the agreement between Staff and KCPL "appears just and reasonable". In KCPL's next Missouri rate case, Case No. ER-2007-0291, Staff and KCPL continued this same treatment of deferring and amortizing the Missouri jurisdictional portion of KCPL's STB litigation costs.

In the KCPL rate case subsequent to the 2008 STB ruling, Case No. ER-2009-0089, KCPL calculated a rate recovery for STB costs and reparations from UPRR in excess of its STB costs of $1.38 million. KCPL distributed this excess to the three entities that it claimed contributed funds to the cost of prosecuting the STB case. These entities were the City of Independence (through its capacity contract with KCPL), Missouri regulated customers, and

Kansas regulated customers. In addition, KCPL allocated a portion of the excess to its wholesale customers who apparently did not contribute funds to the cost of the STB complaint case.

KCPL updated this calculation in the 2009 rate case based on corrected information and included additional reparations received from UPRR. Staff used the calculation methodology in KCPL's work paper, with two corrections.

First, KCPL failed to include all of the funds that were included in Case No. ER-2007-0291 rates in the total amount of the STB costs contributed by Missouri ratepayers. Staff added $143,945, the amount KCPL collected in rates from January 2008 through September 2008. This amount was earmarked for STB case expense recovery, but was excluded by KCPL in its calculation. Second, since KCPL's wholesale customers did not contribute to the STB rate case recovery, Staff reallocated the amounts credited to Missouri and Kansas regulated customers by using the appropriate Missouri-Kansas allocation percentage.

The Non-Unanimous Stipulation and Agreement in Case No. ER-2009-0089, approved by Commission Order effective June 23, 2009, states in part, "the Missouri jurisdictional excess of STB litigation proceeds over un-recovered STB litigation costs of $1,017,593 will be deferred in a regulatory liability account and amortized over ten (10) years beginning with the date new rates become effective in this case, with one year's amortization included in cost of service in this case. The unamortized balance will not be included in rate base." Rates became effective September 1, 2009 and are still being collected. The test year amount on KCPL's books reflects the appropriate amortization level; therefore, no adjustment was necessary for this case.

Staff Expert/Witness: Karen Lyons

C. Payroll, Payroll Related Benefits including 401k Benefit Costs

1. <u>Payroll Costs</u>

Staff examined the payroll costs of KCPL and recommends allocating KCPL's annualized payroll costs using ratios derived from how KCPL recorded its allocated payroll costs during the test year. Staff recommends annualizing KCPL's payroll based on KCPL's actual employee levels as of the end of the update period, June 30, 2016, plus directly assigning Wolf Creek payroll. Because KCPL is the only Great Plains entity that has employees, KCPL employees perform all services for Great Plains, KCPL, and GMO, and certain portions of KCPL's non-regulated enterprises. Since KCPL employees perform all services for Great Plains and its subsidiaries, allocating KCPL's payroll costs is necessary to assign the proper amounts of payroll costs to each of the Great Plains entities, including KCPL. Staff reviewed KCPL's historical allocation of its payroll costs to each of these entities then allocated KCPL's annualized payroll based on this historical allocation. Staff's annualized payroll includes base wages, overtime wages, differential wages, and premium pay paid to KCPL's union employees based on union contracts, as well as an annualized level of payroll for the Wolf Creek generation facility (Wolf Creek payroll is discussed further below).

Staff annualized KCPL's payroll costs in this case based on the actual number of KCPL employees as of June 30, 2016, the end of the update period. Each individual employee's current hourly wage or salary was annualized to compute an annual total payroll cost for that KCPL employee. After KCPL's base payroll was annualized, payroll costs linked to employees of KCPL's jointly-owned generation facilities were allocated based upon a three-year average of actual joint-owner billings. The following table shows KCPL's ownership share of jointly owned plant facilities:

Power Plant	KCPL's Ownership Share	Other Ownership Shares
La Cygne 1	50%	50%
La Cygne 2	50%	50%
Iatan 1	70%	30%
Iatan 2	55%	45%

After removing payroll allocated to joint-owners, Staff allocated KCPL's remaining base payroll costs among KCPL and its affiliates. To do that, Staff used allocation ratios based on the actual payroll allocation that occurred during the 12-month period ended June 30, 2016. To annualize KCPL's overtime wages, Staff multiplied the last-known composite hourly rate for overtime by a three-year average (2013-2015) of KCPL-only overtime hours as the volume of overtime hours has fluctuated in recent years. To annualize wages for premium pay, Staff included the actual expense recorded during the 12-month period ended June 30, 2016 as costs have been increasing. To annualize wages for temporary employees, Staff included a three-year average of expense as costs have been fluctuating. The sum of these four types of payroll costs (base, overtime, premium, and temporary) is Staff's annualized KCPL payroll.

After allocating the KCPL's annualized payroll to Great Plains, KPCL, and GMO, Staff further allocated the KCPL-only payroll costs between Operations & Maintenance ("O&M") Expense and Non-O&M Expense in order to calculate the ongoing O&M payroll expense. Typically, non-O&M expense relates to construction or other capital projects (capital), along with non-utility functions of the company (below-the-line). The amounts that are included in the revenue requirement calculations for KCPL are the O&M levels of total payroll expense after the application of an O&M expense ratio. An examination of the historical capitalized payroll revealed that the actual capitalization ratios have fluctuated from year to year. Staff used a three-year average of historical O&M expense ratios to calculate the proper level of payroll costs to charge to KCPL's O&M expense.

Staff did not adjust payroll expense in this case for payroll related to KCPL's DSIM programs. DSIM costs, including payroll and payroll related costs, are discussed by Staff witness Dana E. Eaves in this report.

The Wolf Creek generating station is managed by a separate entity, Wolf Creek Nuclear Operating Company ("WCNOC"), which charges Wolf Creek payroll directly to KCPL for its share (based on 47% KCPL plant ownership) of the total Wolf Creek payroll expenses. Since WCNOC directly assigns the appropriate portion of Wolf Creek payroll to KCPL, and KCPL is the only Great Plains entity that has an ownership share of Wolf Creek as of June 30, 2016, there is no need to allocate the Wolf Creek payroll costs WCNOC assigned KCPL between KCPL's affiliates. For Wolf Creek base payroll, Staff included the last known annual amount, as costs have been increasing. For Wolf Creek overtime, Staff included the amount of overtime cost WCNOC assigned to KCPL for calendar year 2015, as Wolf Creek overtime costs have trended downward over the four-year period from 2012 through 2015.

After allocating KCPL's total payroll costs to joint-owners, affiliates, and O&M, Staff distributed its resulting payroll adjustment among FERC accounts based upon how KCPL distributed its actual payroll costs among those same accounts during the test year, December 31, 2015. The following are the adjustments Staff made to allocate the annualized payroll to each of these FERC accounts:

Adjustments E-4.1, E-7.1, E-15.1, E-18.1, E-21.1, E-25.1, E-35.1, E-38.1, E-41.1, E-44.1, E-47.1, E-54.1, E-58.1, E-59.1, E-61.1, E-62.1, E-75.1, E-77.1, E-79.1, E-84.1, E-86.1, E-98.1, E-103.1, E-104.1, E-105.1, E-108.1, E-109.1, E-110.1, E-111.1, E-118.1, E-119.1, E-124.1, E-125.1, E-126.1, E-127.1, E-130.1, E-135.1, E-137.1, E-138.1, E-139.1, E-146.1, E-147.1, E-148.1, E-149.1, E-150.1, E-151.1, E-152.1, E-153.1, E-154.1, E-155.1, E-158.1, E-159.1, E-160.1, E-161.1, E-162.1, E-163.1, E-164.1, E-165.1, E-166.1, E-170.1, E-171.1, E-172.1, E-176.1, E-179.1, E-180.1, E-187.1, E-192.1, E-193.1, E-198.1, E-201.1, E-204.1, E-209.1, E-210.1, E-219.1, E-220.1, E-224.1, E-228.1, E-235.1.

Staff Expert/Witness: Matthew R. Young

a. Missouri Energy Efficiency Investment Act Labor Adjustment

KCPL is proposing an adjustment of $1,078,773[70] that would remove labor costs associated with its approved energy efficiency programs from permanent rates and seek cost recovery through its Demand Side Investment Mechanism Rider ("DSIM Rider").[71]

Staff is opposed to KCPL making this adjustment in this case. Labor expense is unique and has a historical cost recovery methodology, and by moving away from this cost recovery methodology it would needlessly shift the cost recovery risk away from the Company to the customer. There also exists the possibility of double recovery of labor cost if those costs are allowed to be recovered through KCPL DSIM Rider without safe guards. KCPL has not proposed any such safe guards. The risk of double recovery can occur when an employee that was included in the labor annualization for permanent rates bills time to KCPL's MEEIA programs. KCPL would recover labor cost in permanent rates once the rates are set in the rate case. Any changes in labor costs are not reflected in rates. KCPL would then recover the same costs again in the DSIM Rider. Also, KCPL's DSIM Rider[72] does not specifically list Company labor cost as a program cost item for recovery. Program costs as defined in KCPL's DSIM Rider:

> "Program Cost" means program expenditures, including such items as program design, administration, delivery, end-use measures and incentive payments, evaluation, measurement and verification, market potential studies and work on a statewide technical resource manual.[73]

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70 *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2016-0285 (*Direct Testimony of Ronald Klote*, filed July 1, 2016) CS-50 Payroll Annualization KCPL-MO Direct, KCPL Summary Tab.

71 On April 6, 2016, the Commission approved KCPL's Demand-side Investment Mechanism ("DSIM") Rider in Case No. EO-2016-0240, which provides for periodic rate adjustments between general rate cases.

72 Kansas City Power & Light, MO.P.S.C. Schedule No 7, Third Revised Sheet No. 49.

73 Kansas City Power & Light, MO.P.S.C. Schedule No 7, First Revised Sheet No. 49A.

For these reasons Staff is opposed to KCPL's proposed Pro forma MEEIA labor adjustment as proposed in this case.

Staff Expert/Witness: Dana E. Eaves

2. Payroll Related Benefits

KCPL incurs costs for a variety of payroll-related benefits, such as 401k matching and employee insurance premium contributions. Staff included the most recent historical cost level, as of June 30, 2016, in its determination of KCPL's cost of service for all payroll benefits, excluding 401k matching costs, as costs have been increasing. Because it is additional employee compensation, Staff allocated payroll-related benefits to the owners of jointly-owned generating stations using the same method Staff utilized to allocate the associated base payroll costs of those employees. That method is described in the payroll section of this report.

Staff calculated KCPL's annualized 401k costs by applying an average of actual 401k percentage match to KCPL's share of total annualized payroll costs. Staff calculated the average percentage match by dividing the percentage of KCPL's actual 401k match by the actual 401k eligible payroll expense in seven separate pay periods, and averaging those ratios. Staff Adjustments E-214.1 and E-214.2 to Staff's Income Statement (EMS Schedule 9) reflect Staff's normalized payroll benefits, based on KCPL's payroll costs as of the update period of June 30, 2016.

Staff Expert/Witness: Matthew R. Young

3. Payroll Taxes

Staff annualized KCPL's payroll taxes by applying current payroll tax rates to each employee's annualized level of payroll and each employee's last known receipt of Value-Link incentive compensation. To calculate payroll taxes on executive incentive compensation, Staff applied the current tax rate for Medicare tax to Staff's annualized executive incentive compensation under the assumption the all tax wage ceilings were achieved through base payroll. To compute payroll taxes for overtime, temporary labor, premium pay, and Wolf Creek payroll, Staff applied the current payroll tax rates to these "other" wages assuming the Federal Unemployment Tax Act ("FUTA") and State Unemployment Tax Act ("SUTA") wage ceilings were achieved. To allocate Staff's annualized payroll taxes to the various subsidiaries of Great

Plains, Staff used the same method that it used to allocate KCPL's payroll costs. Staff Adjustment E-258.1 to Staff's Income Statement (EMS Schedule 9) reflects the annualized payroll taxes based on payroll costs as of June 30, 2016.

Staff Expert/Witness: Matthew R. Young

4. <u>True-up of Payroll Costs</u>

Staff will update the total payroll costs, payroll-related benefits, and payroll taxes based on actual historical information through December 31, 2016, for the true-up in this case. Unless true-up data indicate a change in circumstance, the same methodology used to annualize payroll as of June 30, 2016 will be used for the true-up.

Staff Expert/Witness: Matthew R. Young

5. <u>FAS 87 – Pension Cost Tracking Mechanism</u>

Staff and KCPL entered into a *Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post Employment Benefits* ("Agreement") in KCPL's 2014 rate case, Case No. ER-2014-0370, dated June 26, 2015. Among other items, this Agreement addressed the ratemaking treatment for annual pension costs under Financial Accounting Standard No. 87 ("FAS 87"), and pension settlement and curtailment accounting under Financial Accounting Standard No. 88 ("FAS 88"). The Agreement was clarified and modified by the *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*, Case No. ER-2014-0370. Both stipulation and agreements were approved by the Commission in that case.

The names of the FASs have recently changed. The Financial Accounting Standards Board's ("FASB") Accounting Standards Codification project was launched in 2009 and became the single source of authoritative nongovernmental U.S. Generally Accepted Accounting Principles ("GAAP") (other than guidance issued by the Securities and Exchange Commission). The new Codification Topic 715 covers all of the following FAS statements under its various subtopics:

- FAS 87 and FAS 88, Employers' Accounting for Pensions;
- FAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans; and
- FAS 106, Employers' Accounting for Post Retirement Benefits other than Pensions.

While the above individual FAS statements have been combined into Codification Topic 715, for the purposes of this Report, Staff will use the original FAS statement numbers, such as FAS 87, FAS 88, FAS 106, and FAS 158, as needed.

The Agreement reaffirmed the prior provisions regarding these matters reached in KCPL's Regulatory Plan and subsequent rate cases, and clarified the accounting for pension cost allocated to KCPL's joint partners in the Iatan and La Cygne generating stations. It also addressed the ratemaking treatment for a curtailment or settlement recognized under FAS 88.

There are two amounts in KCPL's rate base relating to pensions resulting from various agreements reached in Case Nos. EO-2005-0329, ER-2006-0314, ER-2007-0291, ER-2009-0089, ER-2010-0355, ER-2012-0174, and ER-2014-0370:

> 1) A Prepaid Pension Asset – The prepaid pension asset represents the unrecovered balance of negative pension cost flowed back to ratepayers in prior years. A prepaid pension asset can also be created when contributions to the pension plans exceed the FAS 87 expense.
>
> 2) A FAS 87 Regulatory Asset – Under the terms of the Stipulation and Agreements referenced above, the difference between FAS 87 reflected in rates and KCPL's actual cost recorded in its financial statements is tracked and recorded as either a regulatory asset or liability, and is then amortized over five years in the next rate case. The cumulative tracker balance as of June 30, 2016 is a regulatory asset; that is, the amount collected in rates has been less than the incurred FAS 87 expense.

Staff's recommended annualized level of KCPL pension expense is based on information provided by KCPL's actuarial firm, Towers Watson, which KCPL in turn provided to Staff in response to Staff Data Request No. 0223. Staff's calculation of KCPL's pension expense was made in accordance with the methodology described in the Agreement reached in Case No. ER-2014-0370.

Based on the language of the Agreement in Case No. ER-2014-0370, Staff recommends cost of service recovery of KCPL's share of FAS 88 charges through a five-year amortization increase to pension expense.

The FAS 88 charge is related to the impact on pension expense of employees being removed from KCPL's pension plans and the impact of paying lump sum pension distributions to these employees in the alternative. While the FAS 88 charge is an increase to cost of service, the ongoing level of pension expense should be lower due to the removal of these employees' costs from the pension plan.

Ongoing pension expense and the rate base portion of the pension tracker mechanism are included in Staff Adjustment E-210.2 in the Income Statement – Schedule 10, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

6. FAS 106 – Other Post Employment Benefit Cost Tracking Mechanism

Staff and KCPL entered into a *Non-Unanimous Stipulation and Agreement Regarding Pensions and Other Post Employment Benefits* ("Agreement") in KCPL's 2014 rate case, Case No. ER-2014-0370, dated June 26, 2015. Among other items, this Agreement addressed the ratemaking treatment for annual Other Post Employment Benefit ("OPEB") Costs under Financial Accounting Standard No. 106 ("FAS 106"). The Agreement was clarified and modified by the *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*, Case No. ER-2014-0370. Both stipulation and agreements were approved by the Commission in that case.

OPEBs are those costs KCPL incurs to provide certain benefits to KCPL retirees. The primary benefit is medical insurance, but they also include life, dental, and vision insurance benefits.

FAS 106 is the FASB approved accrual accounting method used for financial statement recognition of annual OPEB costs, and is also used as the basis of rate recovery for this item. The accounting of the cost of postretirement benefits under FAS 106 is not based on the actual dollars KCPL pays for OPEBs to its retirees currently, but is accrual-based in that it attempts to recognize the financial effects of noncash transactions and events as they occur. These noncash transactions and events are primarily an estimate of current benefits earned by employees before retirement, but will not paid until after retirement, as well as the interest cost arising from the passage of time until those benefits are paid.

KCPL does not fund its share of Wolf Creek OPEB expense based on FAS 106 calculations. KCPL funds Wolf Creek OPEB based on the actual amount of benefits paid, not the FAS 106 calculated accrual. This method is generally referred to as "pay-as-you-go".

Accordingly, the Wolf Creek OPEB costs are not included in the FAS 106 tracking mechanism, but are included separately in the cost of service on a pay-as-you-go basis.

Staff's OPEB adjustment to KCPL Account 926, Employee Benefits, annualizes the level of OPEB expense determined by KCPL's actuaries using the FAS 106 accounting method, with the exception of KCPL's portion of Wolf Creek OPEB expense, calculated as the 12 months ending December 31, 2014 actual payments.

Beginning May 4, 2011, KCPL initiated a new tracking mechanism for OPEBs, which the Commission authorized in Case No. ER-2010-0355. Under this mechanism, what is tracked are the differences between the current ongoing level of OPEB expense funded by KCPL in an external trust and the dollar amount of OPEB expense reflected in rates in each case. The unamortized balance of this tracker will be amortized over five years in each successive rate case, and either will be added to or subtracted from the level of OPEB expense as determined by KCPL's actuaries. The cumulative tracker balance as of June 30, 2016 is a regulatory liability; that is, the amount collected in rates has been more than the incurred FAS 106 OPEB expense. As with other rate base, prepaid pension and other pension assets, it is anticipated that the OPEB tracker liability will be updated through the December 31, 2016 true-up period.

Ongoing OPEBs expense and the rate base portion of the OPEB tracker mechanism are included in Staff Adjustments E-211.2 in the Income Statement – Schedule 10, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

7. <u>Supplemental Executive Retirement Plan ("SERP") Expense</u>

Included in Staff's revenue requirement recommendation is an annualized level of actual monthly-recurring SERP payments KCPL made to its former executives and other highly compensated former employees. SERPs are "non-qualified" retirement plans for officers and other highly-compensated employees that provide pension benefits that these individuals would have received under other company retirement plans, but for compensation and benefit limits imposed by the Internal Revenue Service ("IRS"). These supplemental pension benefits paid to retired former officers and executives are in addition to the cost of pension benefits KCPL pays under its FAS 87 pension plan. SERP pension benefits generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. SERP benefits are not externally funded to a trust by KCPL, and the amounts Staff included in is cost of service of KCPL are based upon actual cash SERP payouts to covered employees.

SERP payments can consist of either monthly annuity payments or periodic lump-sum distributions. Lump-sum payments can be significant and the timing of these payments are often difficult to predict. As opposed to including a normalized amount of actual lump-sum payments, KCPL used a conversion factor of 14.3 to convert prior lump-sum payments to an amount that approximates the equivalent annuity payments to the qualifying employees as if that lump-sum payment option were not elected. Staff utilized this factor for the calculation of a normalized level of converted lump-sum payments.

KCPL and GMO currently charge a portion of SERP costs to plant accounts, also known as capitalizing these costs. In the response to Staff Data Request 229.1, KCPL identified that a portion of SERP has been capitalized for "a number of years" and there has been no change in that policy. The cumulative portion of capitalized SERP is included in the plant in service balances in Staff Accounting Schedule 3 as a portion of construction costs. Because KCPL capitalizes SERP costs, Staff has included a reduction in SERP expense commensurate with the capitalization rate used in Staff's payroll adjustment in this case.

Staff recommends that a three year average of monthly annuity payments, and a three year average of converted lump-sum payments, be used in this rate case to determine allowable SERP expense in rates. This approach is reflected in Staff Accounting Schedule 10, Adjustment E-210.3.

Staff Expert/Witness: Keith Majors

8. Severance Expenses

Staff recommends removal of employee severance payments incurred during the test year. Severance payments are cash payments to former employees paid for various reasons. Severance agreements typically include commitments from the former employee to not pursue litigation against the company and its officers.

Severance payments are non-recurring in regards to the specific employee. Because of the unique nature of cost of service ratemaking, utilities are able to recover severance payments through regulatory lag. Between the time the employee is terminated and rates are changed in the next rate case, KCPL collects both the salary and wages of the terminated employee and benefit costs. These amounts can accumulate to more than the severance paid.

The adjustments for the removal of severance expenses are in Staff Accounting Schedule 10, Adjustments E–E-119.5 and E-201.7.

Staff Expert/Witness: Keith Majors

9. <u>Short Term Annual Incentive Compensation</u>

KCPL has two short-term annual incentive compensation plans for executive and management employees. These plans are designed to grant cash awards of various amounts that are calculated based upon designated annual metrics. Incentive compensation accrues over a calendar year and is paid out in the first quarter of the following calendar year. The two incentive compensation plans are 1) the Value-Link Plan, reserved for non-union, non-executive KCPL employees; and 2) the Annual Executive Incentive Plan, reserved for senior management-level KCPL employees.

The incentive plans all have benchmarks that identify targets that KCPL employees are expected to achieve before any cash payouts are awarded. These targets are established each year of the incentive plan and communicated to the employees early enough so that the employees have sufficient opportunity to reasonably achieve the benchmarks.

Staff has historically disallowed payouts from KCPL's Value-Link incentive compensation plan related to attaining certain financial metrics, such as Earnings per Share ("EPS"), on the basis that these metrics are to benefit shareholders and not ratepayers. In addition, the Commission has historically disallowed the awarding of incentive compensation tied to the utility achieving certain corporate financial goals on the basis that these goals provide no direct benefit to Missouri ratepayers. *See* specifically *Re KCPL*, Case Nos. ER-2006-0314, 15 Mo.P.S.C.3d 138, 171-72 (2006) and *Re KCPL*, ER-2007-0291, pp. 49-51 (2007).

The Value-Link plan has listed an EPS component as a metric for incentive payouts during the plan years 2012 through 2015. However, the Value-Link plan for the calendar year 2016 does not have an EPS component, which makes historical plan years less relevant to future incentive compensation awards. To normalize incentive compensation expense related to the Value-Link plan, Staff averaged three of the four most recent plan years (2012, 2014, and 2015) to include in KCPL's cost of service. During the plan years included in Staff's average,

** ** Staff cannot base its recommended incentive compensation expense on the 2016 Value-Link plan because the actual payout will not be known and measurable until late in the first quarter of 2017, when the payout is awarded to employees.

For consistency, Staff's normalized expense for the executive plan is an average of the payouts for the same plan years above (2012, 2014, and 2015), less payouts for EPS metrics. Staff then allocated its normalized incentive compensation amounts to the affiliates of KCPL, and between O&M and Non-O&M expenditures. Staff Adjustments E-4.3, E-98.2, E-108.2, E-119.2, E-124.2, E-146.2, E-154.3, E-164.2, E-170.2, E-171.2, E-172.2, E-187.2, E-198.3, and E-214.3 reflect KCPL's jurisdictional O&M expense portion of incentive compensation.

Staff Expert/Witness: Matthew R. Young

10. Capitalized Long-Term Incentive Equity Compensation

Great Plains offers an equity-based Long Term Incentive Plan ("LTIP"), the cost of which is partially allocated to KCPL. Staff has removed the LTIP expense KCPL recorded in the test year ended December 31, 2015. The Commission denied recovery of stock-based incentive compensation in its *Reports and Orders* in KCPL Case Nos. ER-2006-0314, 15 Mo.P.S.C.3d 138, 171-72 (2006) and ER-2007-0291, 15 Mo.P.S.C.3d 552, 585-87 (2007). In Case Nos. ER-2010-356 and ER-2012-0175, GMO voluntarily removed LTIP related costs from its cost of service. In its *Report and Order* in KCPL Case No. ER-2014-0370 at page 68, in the context of a discussion of rate case expense, the Commission noted, "Utility expenses that are highly discretionary and do not benefit customers, such as charitable donations, political lobbying expenses, and incentive compensation tied to earnings per share, are typically allocated entirely to shareholders." (Footnote omitted).

Beginning in 2014, KCPL began charging to its capital accounts a portion of the LTIP costs Great Plains allocated to it. Before 2014, no part of these costs was capitalized. Because it is inappropriate to recover stock-based compensation as an expense in the cost of service, it is also inappropriate to recover stock-based compensation as capital (plant-in-service) included in rate base. Therefore, Staff recommends the amounts of LTIP expense that KCPL has capitalized should be removed from KCPL's plant in service. Staff's adjustments to do so are included in Staff's Accounting Schedule 3 – Plant in Service, Adjustments P-322.1

Staff Expert/Witness: Keith Majors

D. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expenses and clearing accounts. It includes labor, materials, overheads, and any other expenses incurred in maintaining the Company's assets - including power plants, transmission and distribution network of the electric system, and the general plant. Specific types of maintenance work tied to specific classes of plant are listed in functional maintenance expense accounts in the FERC USOA for the various types of utilities. Maintenance expense normally consists of the costs of the following activities:

- Direct field supervision of maintenance;
- Inspecting, testing and reporting on condition of plant, specifically to determine the need for repairs and replacements;
- Work performed with the intent to prevent failure, restore serviceability or maintain the expected life of the plant;
- Testing for, locating, and clearing trouble;
- Installing, maintaining, and removing temporary facilities to prevent interruptions; and
- Replacing or adding minor items of plant, which do not constitute a retirement unit.

Staff analyzed maintenance costs from 1999 through June 30, 2016, by functional area for production, transmission, distribution, and general plant by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are separately addressed as a component in the cost of service analysis, labor costs were removed from Staff's analysis in order to perform a review of non-labor maintenance costs only.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by the Staff was to compare functional averages, which included using a two (2)-year average through a seven (7)-year average to determine if there were fluctuations with each functional area. Each of the costs by year and averages for maintenance were also compared to results for the test year, the 12-month period ended December 31, 2015, and the update period ended June 30, 2016. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annualized level of KCPL's maintenance costs to include in rates. Staff will review non-labor maintenance expense again during the true-up phase of this case. Staff's results are presented in the following table:

Results of Staff's Non-Labor Maintenance Analysis	
Steam Production Maintenance	12-Month Test Year Ended December 31, 2015
Nuclear Production Maintenance	12-Month Test Year Ended December 31, 2015
Other Production Maintenance	12-Month Test Year Ended December 31, 2015
Transmission Maintenance	12-Month Test Year Ended December 31, 2015
Distribution Maintenance	12-Month Test Year Ended December 31, 2015
General Maintenance	12-Month Test Year Ended December 31, 2015

As identified in the table above, Staff decided to use the 12-month test year ended December 31, 2015, account balances to represent future maintenance costs for Production Nuclear, Other Production, Transmission and Distribution for purposes of its direct case filing. Staff used the 12-month test year period to reflect a level of normalized maintenance for these costs based on actual information provided by KCPL for a period of several years. This historical information was analyzed to determine the proper level of maintenance which should be included in KCPL's cost of service in this case.

For Wolf Creek, there are two types of O&M costs – O&M for general plant, and O&M relating to the refueling outages that occur every 18 months. Staff performed separate analyses for each. A discussion of the O&M expenses related to the Wolf Creek refueling is located under the heading *Wolf Creek Nuclear Refueling Outage* in this report.

Staff Expert/Witness: Michael Jason Taylor

1. Wolf Creek Nuclear Refueling Outage

Staff included an annualized level of refueling cost for refueling outage #20, completed in spring of 2015, and an amortization of non-routine maintenance cost that occurred during refueling outage #18 as calculated and agreed to in the KCPL rate case, File No. ER-2012-0174. Staff reviewed information provided by KCPL for the last seven nuclear refueling outages. While refueling costs have generally increased since refueling #14, they declined from refueling #19 to refueling #20. The only significant increase was from refueling #17 to refueling #18. Staff determined the age of the plant and unplanned equipment issues led to the increased costs experienced with outage #18.[74]

The costs on KCPL's books associated with Wolf Creek refueling outage #20 have been deferred and amortized over a 18-month period. Adjustments E-68.2 and E-80.2 reflect the annualized amortization of #20 refueling costs.

In addition to costs for refueling outage #20, Staff reflected the refueling amortizations established in the previous KCPL rate case – refueling #18, File No. ER-2012-0174. The amortization was established for non-routine maintenance costs that occurred during refueling #18. The amortization of the non-routine maintenance costs that occurred during refueling #18 began February 2013 and will end January 2018. The test year amount recorded on KCPL's books reflects the appropriate amortization level; therefore, no adjustment was necessary for this amortization. Once the amortization of the non-routine maintenance costs that occurred during refueling #18 are fully amortized, KCPL will be collecting funds in rates for expenses it is no longer incurring. Consistent with the *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*[75] in File No. ER-2014-0370, Staff recommends that once amortization of refueling #18 is complete, KCPL apply the funds that will continue to be collected through rates to offset future refueling costs.

Staff Expert/Witness: Michael Jason Taylor

[74] Staff Data Request No. 0147.2 in Case No. ER-2012-0174.
[75] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2014-0370, (*Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*, filed July 1, 2015) page 3. The Commission issued an *Order Approving Stipulation and Agreement Regarding Certain Issues* on July 17, 2015.

2. **Wolf Creek Mid-Cycle Outage**

KCPL's test year in File No. ER-2014-0370 included a planned mid-cycle outage at the Wolf Creek generating station that occurred between refueling #19 and refueling #20. The mid-cycle outage began March 8, 2014, and was completed on May 13, 2014, and was not related to the refueling outages that occur every 18 months. The mid-cycle outage resulted in maintenance expense, but did not include refueling. The maintenance work completed during the mid-cycle outage resulted in less maintenance work being required during refueling outage #20 than what would normally be expected during a refueling. Refueling 20 began February 28, 2015, and was completed on May 3, 2015.

Pursuant to the *Partial Non-Unanimous Stipulation and Agreement as to True Up, Depreciation and Other Miscellaneous Issues* and the *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*[76] in File No. ER-2014-0370, both filed on July 1, 2015, and approved by the Commission on July 17, 2015, KCPL was authorized to create a regulatory asset and amortize the costs related to the mid-cycle outage over a five (5)-year period. The amortization of these costs commenced with the charging of the new rates authorized by the Commission in File No. ER-2014-0370 on September 29, 2015. Staff included an annualized level of the Wolf Creek mid-cycle amortization in Staff's Accounting Schedules, Adjustment E-68.1 and E-80.1.

Staff Expert/Witness: Michael Jason Taylor

3. **Nuclear Decommissioning**

In its *Order Approving Stipulation And Agreement* in File No. EO-2012-0068, the Commission ordered the following:

> …
>
> 3) Kansas City Power & Light Company's retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264.

[76] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2014-0370, (*Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*, filed July, 1, 2015) page 3. The Commission issued an *Order Approving Stipulation and Agreement Regarding True Up, Depreciation, and Other Issues* and an *Order Approving Stipulation and Agreement Regarding Certain Issues* both on July 17, 2015.

> 4) The current decommissioning costs for Wolf Creek are included in Kansas City Power & Light Company's current Missouri cost of service and are reflected in its current Missouri retail rates for ratemaking purposes.[77]

In its *Order Approving Stipulation And Agreement* in File No. EO-2015-0056, the Commission ordered the following:

> …
>
> 4) Kansas City Power & Light Company's retail jurisdiction annual decommissioning expense accruals and trust fund payments shall continue at the current level of $1,281,264.
>
> 5) Kansas City Power & Light Company is authorized to continue to record and preserve Wolf Creek asset retirement obligation costs, as agreed by the Commission Staff, the Office of the Public Counsel, and KCP&L and authorized by the Commission in Case No. EU-2004-0294.
>
> 6) This order shall become effective on January 21, 2015.[78]

Staff found the KCPL test year decommissioning expense reflected the amount ordered by the Commission; therefore, no adjustment was necessary.

Staff Expert/Witness: Matthew R. Young

4. <u>Meter Replacement Program – Incremental Meter Reading Costs</u>

In 2014, KCPL began installing Advanced Metering Infrastructure (AMI) technology that will replace all of the Company's Automated Meter Reading ("AMR") meters. KCPL entered into a new meter reading contract during the pendency of Case No. ER-2014-0370 associated with the newly installed AMI meters. The new contract increases the composite meter reading cost from ** ____________________ ** per meter. Staff Adjustment E-171.3 reflects the meter reading cost associated with the new AMI meters.

Staff Expert/Witness: Michael Jason Taylor

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77 *In the Matter of Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels,* Case No. EO-2012-0068 (*Order Approving Stipulation and Agreement)*, at page 3.

78 *In the Matter of the Application of Kansas City Power & Light Company for Approval of the Accrual and Funding of Wolf Creek Generating Station Decommissioning Costs at Current Levels,* Case No. EO-2015-0056, (*Order Approving Stipulation and Agreement)*, at page 3.

5. **Iatan Unit 2 O&M Expenses**

In Case No. ER-2010-0355, Staff recommended a tracker for Iatan Unit 2 O&M expense, so the actual cost of the O&M expense related to Iatan Unit 2 would be recovered through rates in future rate cases. Since Iatan Unit 2 was placed in service on August 26, 2010, and KCPL's operational experience with Iatan Unit 2 was non-existent at the time of Case No. ER-2010-0355, an O&M tracker was suggested to protect both KCPL and its customers from including projected costs in rates that would in all likelihood vary from the actual costs associated with Iatan Unit 2's O&M expense. KCPL and other signatory parties agreed through a Non-Unanimous Stipulation and Agreement in Case No. ER-2010-0355 to establish a tracker for Iatan Unit 2 costs and on April 12, 2011, the Commission approved the use of a tracker for these costs.

In File No. ER-2012-0174, a three (3)-year amortization of the actual Iatan Unit 2 costs that exceeded the base rates established in Case No. ER-2010-0355 was included in KCPL's cost of service. In addition, a new base level was established for the Iatan Unit 2 tracker and also included in KCPL's cost of service on a going-forward basis. At the time of the 2012 rate case, KCPL still only had limited operating experience with the two (2)-year old plant.

The three (3)-year amortization that was established in File No. ER-2012-0174 is referred to as Vintage 1. The effective date of rates in File No. ER-2012-0174 was January 26, 2013. The amortization period for Vintage 1 ended January 26, 2016. Since the amortization period has ended, Staff made an adjustment to eliminate the annual amortization from the test year, 12 months ending December 31, 2015.

In Case No. ER-2014-0370, a three (3)-year amortization of the actual Iatan Unit 2 costs that exceeded the base rates established in File No. ER-2012-0174 was included in KCPL's cost of service. In addition, the tracker was discontinued in that case. Iatan Unit 2 O&M costs are now treated as a normal component of O&M expense in the cost of service just like the expenses associated with all the other power plants operated by KCPL.

Although the Iatan 2 tracker has been discontinued, rate case adjustments still need to be made until the balances are fully amortized. There are five "vintages" of deferred costs established with the Iatan 2 tracker. Staff's adjustment E-5.1 and E-42.1 reflect an annualized amount of amortization expense for vintages two through five.

Given the limited experience with operating and maintaining Iatan Unit 2, when it was placed in service, a O&M tracker was established to protect KCPL and its customers. The tracker is not intended to allow KCPL to over-recover the actual O&M expenses incurred for Iatan Unit 2 but to recover the actual reasonable and prudent costs. It was not intended that the O&M tracker for Iatan Unit 2 allow for KCPL to profit at the ratepayers' expense because of a lack of foresight in addressing the matter of an end date in rates at the conclusion of the intended amortization period. Consistent with the *Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*[79] in Case No. ER-2014-0370, KCPL agreed to track the over-collection of vintage 1 to offset vintage 2. Staff has reflected this offset as described below.

Since the amortization period for vintage 1 ended in January 2016, KCPL customers will continue to pay for vintage 1 through the effective date of rates in this case. Consequently, Staff offset vintage 2 with the over-collection for the period of January 2016 through the update period of June 2016. During the true-up phase of this case, Staff will make a similar adjustment but for the period of January 2016 through December 2016. Pursuant to the stipulation referenced above, KCPL agreed to track any over-collection associated with any amortization established as a result of the Iatan Unit 2 tracker and apply the over-recovery as an offset to other Iatan 2 vintages in subsequent KCPL rate cases.

Staff Expert/Witness: Michael Jason Taylor

6. <u>IT Software Maintenance</u>

KCPL incurs costs associated with contracts to maintain its information technology ("IT") hardware and software that include, but are not limited to, Microsoft, PowerPlan, and Oracle. KCPL prepays the software maintenance vendor and amortizes the balance of the costs over the life of the contract. Staff reviewed KCPL's prepaid IT software maintenance for the update period in this case, 12 months ending June 30, 2016. During its review, Staff found that KCPL renewed several contracts in 2015 and 2016. If a contract was renewed, Staff included the current contract price in its annualization, and omitted contracts that expired and were not subsequently renewed.

[79] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2014-0370, (*Partial Non-Unanimous Stipulation and Agreement as to Certain Issues*, filed July 1, 2015) page 3. The Commission issued an *Order Approving Stipulation and Agreement Regarding Certain Issues* on July 17, 2015.

Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustments E-21.5, E-119.4, E-130.4, E-166.2, and E-235.2. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

7. <u>Critical Infrastructure Protection and Cyber-Security</u>

Staff analyzed KCPL's actual non-labor Cyber-Security and Critical Infrastructure Protection ("CIP") costs from the period of 2009 through June 2016. The North American Electric Reliability Corporation ("NERC") established a set of requirements designed to secure utility assets that are required for operating North America's bulk electric system. KCPL's historical

Cyber-Security and CIP non-labor costs are identified in the following table:

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As reflected in the table above, Staff found the costs for CIP and Cyber-Security showed an upward trend through December 31, 2015, but are beginning to decline through the first six months of 2016. Consequently, Staff annualized the non-labor CIP and Cyber-Security costs using the 12 months ending June 30, 2016. Consistent with other rate case expenses, Staff did not include internal labor costs for CIP and Cyber-Security as those are included in the cost of service through Staff's payroll annualization. Staff's adjustments are identified on Schedule 9 of Staff's Accounting Schedules, Adjustments E-21.1, E-119.3, E-124.3, E-130.2, E-198.4, E-201.5, E-205.2, E-211.1, and E-235.3.

Staff Expert/Witness: Karen Lyons

E. Other Non-Labor Adjustments

1. Bad Debt Expense

Staff's recommended treatment of bad debt expense is to calculate the ratio of KCPL's net write-offs to annualized retail revenue to determine an appropriate level of bad debt expense. Bad debt expense is the portion of retail revenues KCPL is unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. If KCPL is subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those collected amounts reduce current write-offs. Offsetting successful collection agency recoveries against total write-offs creates the "net write-off" amount used to determine the annualized level of bad debt expense.

Staff calculated the annualized bad debt expense by examining the ratio between billed revenues, net of gross receipt taxes, for the twelve month period ended December 31, 2015, and the actual 12-month history of billed revenues that were never collected (net write-offs) for the twelve months ended June 30, 2016. From this information a bad debt ratio was derived, which was then applied to Staff's annualized, weather normalized level of retail revenues to obtain the annualized level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with KCPL's position on how bad debt write-offs are accounted.

KCPL asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue. Adjustment E-174.1 in Staff's Accounting Schedules reflects an annualized level of bad debt expense.

Staff Expert/Witness: Matthew R. Young

2. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that KCPL charged to its utility accounts during the test year. Staff in the current case used the four criteria Staff used in Case No. EO-85-185 to establish when dues and donations expenses should not be included in customer rates:

> (1) the expenses are involuntary ratepayer contributions of a charitable nature;
>
> (2) the expenses are supportive of activities which are duplicative of those performed by other organizations to which the Company belongs or pays dues;
>
> (3) the expenses are associated with active lobbying activities which have not been demonstrated to provide any direct benefit to the ratepayers; or,
>
> (4) the expenses represent costs of other activities that provide no benefit or increased service quality to the ratepayer.

Staff's adjustments are identified as follows on Schedule 10 of Staff's Accounting Schedules: Adjustment E-228.4 and E-201.4.

In regard to the first criteria listed above, KCPL accounted for all donations made to charitable organizations as a below-the-line expense amount, and consequently they are not included in the determination of its revenue requirement.

While Staff recognizes the importance of charitable contributions, donations such as those that do not provide any direct benefit to ratepayers and are not necessary for the provision of safe and adequate service should be excluded from KCPL's revenue requirement. In addition, recovery in rates of donations made by regulated utilities would constitute an involuntary contribution on behalf of the rate-paying customer, and thus, those donations were excluded from the Company's revenue requirement.

a. Edison Electric Institute ("EEI") Dues

According to information obtained from the EEI website (www.eei.org), EEI is an association of investor-owned electric utilities and industrial affiliates. Based upon its review of EEI information, Staff determined that the primary function of EEI is to represent the interests of the electric utility industry in the legislative and regulatory arenas. This role includes EEI's engagement in lobbying activities.

In Case No. ER-82-66, a prior KCPL rate increase case, the Commission stated the following:

> …until the Company can better quantify the benefit and the activities that were the causal factor of the benefit, the Commission must disallows EEI dues as an expense.[80]

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

In Case No. ER-83-49, another KCPL rate case, the Commission stated in its Report and Order that EEI dues:

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

In Case Nos. EO-85-185 and EO-85-224, KCPL rate cases the Commission stated in its Report and Order regarding the need for the utility to allocate EEI benefits between ratepayers and shareholders:

> … The argument that allocation is not necessary if the benefits lessen the cost of service to the ratepayers by more than the cost of the dues, misses the point.
>
> It is not determinative that the quantification of benefits to the ratepayer is greater than the EEI dues themselves. The determining factor is what proportion of those benefits should be allocated to the ratepayer as opposed to the shareholder. It is obvious that the interests of the electric industry are not consistently the same as those of the ratepayers. The ratepayers should not be required to pay the entire amount of EEI dues if there is benefit accruing to the shareholders from EEI membership as well. The Commission finds this to be the case. The Company has been informed in prior rate cases that it must allocate its quantified benefits from membership in EEI. That has not been done herein. Therefore, no portion of EEI dues will be allowed in this case.[81]

In the response to Staff Data Request 104.3, KCPL identified that approximately 93% of EEI dues paid in the test year were booked "below the line." Although KCPL allocated most of the benefits most of the expenses of EEI, KCPL failed to identify or quantify any benefit to ratepayers from participation in EEI. Consequently, Staff removed that amount of EEI dues included "above the line" in test year expense from KCPL's cost of service, consistent with prior

[80] See *Re: Kansas City Power & Light Co.*, 25 Mo. P.S.C. (N.S.) 229, 245 (1982).
[81] See *In the Matter of Kansas City Power & Light Co*., 28 MO P.S.C. (N.S.) 228, 259 (1986).

Commission Report and Orders. Staff's adjustments are identified as follows on Schedule 10 of Staff's Accounting Schedules: Adjustment E-228.5, E-201.6, and E-130.4.

Staff Expert/Witness: Michael Jason Taylor

3. Miscellaneous Test Year Adjustments

In its direct filing, KCPL included Adjustment CS-11 which includes several categories of miscellaneous adjustments totaling a reduction of $7,084,630 to its test year cost of service. There are several categories of miscellaneous adjustments within CS-11, such as adjustments to:

a. Remove equity-related incentive compensation;

b. Reclassify the costs of non-recoverable dues and expense reports to "below-the-line;"

b. Miscellaneous coding corrections that occurred after the test year; and

d. Remove the effect of accounting entries made during the test year to comply with the Report and Order in Case No. ER-2014-0370

Staff has reviewed and reflected these adjustments in Staff adjustments E-4.2, E-21.2, E-21.3, E-41.2, E-60.1, E-62.2, E-76.1, E-77.2, E-79.2, E-85.1, E-87.1, E-154.2, E-180.3, E-198.2, E-199.1, E-201.2, E-201.3, E-205.1, E-228.2, E-228.3, E-229.1, E-229.2, E-239.2.

Staff Expert/Witness: Matthew R. Young

4. Legal Fee Reimbursement Amortization

In its direct case, KCPL included Adjustment CS-115 to remove the amortization of a legal fee reimbursement that was amortized over three (3) years, in File No. ER-2012-0174. The Missouri jurisdictional balances of these reimbursements are treated as regulatory liabilities on KCPL's books and records. The reimbursement was related to personal injury claim legal fees.

This regulatory liability amortization was amortized as a reduction to cost of service over three (3) years beginning January 27, 2013 – the effective date of rates in File No. ER-2012-0174. This amortization expense is no longer being recorded by KCPL.

Adjustment E-206.1 in Staff Accounting Schedule 9 removes this amortization from the cost of service.

Staff Expert/Witness: Keith Majors

5. Debit/Credit Card Acceptance Program

In February 2007, KCPL implemented a Debit/Credit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. KCPL has implemented the program through two service agreements. The first agreement is with Paymentech, LLC ("Paymentech"), a subsidiary of JPMorgan Chase Bank, N.A., and is for credit and debit card payments. The second agreement is with Speedpay, Inc. ("Speedpay"), a subsidiary of E Commerce Group Products, Inc. (a subsidiary of The Western Union Company), and is for ATM Card and debit card payments made over the telephone. Paymentech and Speedpay act as third party facilitators for the processing of payments to KCPL. Payment options available to customers through the program include payment over the phone, utilizing the Interactive Voice Response System ("IVR"), and/or payment through the KCPL website. Customers are offered two options when paying through the website: one time payments, or recurring payments. The cost for providing this service is absorbed by KCPL and later built into rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in February 2007, customer participation has been gradually increasing. Participation is projected to increase into the future as more customers become aware of the program. As customer participation increases, the per unit transaction cost to KCPL for providing the debit/credit payment service have declined

Staff included in its cost of service an annualized amount associated with the credit and debit card program based upon the total card level and per unit transaction cost as of the twelve months ended June 30, 2016, to represent an ongoing level of costs (Adjustment E-172.3).

Staff Expert/Witness: Michael Jason Taylor

6. Accounts Receivable Bank Fees

KCPL sells its accounts receivable to Kansas City Power & Light Receivables Company ("KCREC"), an affiliated entity. This program increases immediate cash flow to KCPL and provides access to funds through lines of credit. As a result of the immediate cash flow, and the elimination of the need to attempt to collect on its accounts receivable, KCPL reduces the collection lag associated with its CWC requirement. Ratepayers may benefit from the program because cash is generated by the sale of receivables instead of being collected from the ratepayers. The effect of the selling of accounts receivable is that KCPL receives monies faster, shortening the overall revenue lag and reducing KCPL's revenue requirement. It is the entity purchasing the accounts receivable from KCPL that has to wait for the customers to pay over a normal period of time, based on the Commission's billing rules. KCPL has to pay The Bank of Tokyo-Mitsubishi UFJ, Ltd. ("BTM") fees associated with the selling of the accounts receivable. As long as the fees KCPL pays to accelerate its cash recovery through the sale of its receivables are less than the revenue requirement decrease from the shorter collection lag, there is a reasonable likelihood that the sales of accounts receivable provide a customer benefit.

This process works as follows:

- KCPL sells its electric receivables daily at a discount and on a non-recourse basis to KCREC.
- KCREC sells an undivided interest in the receivables to Victory Receivables Corporation ("Victory"), a wholly-owned subsidiary of BTM.
- Victory issues commercial paper to fund the purchase of the receivables from KCREC.
- KCREC uses the cash it receives from Victory to partially pay KCPL for the receivables.
- KCREC gives a promissory note to KCPL for the difference between the partial payment and the total discounted purchase price.
- KCREC pays Victory interest, program fees, and a commitment fee.
- KCREC pays KCPL interest on the promissory note.

The adjustment for bank fees relates to the cost of the sale of its accounts receivable. Staff included the test year level of bank fees paid by KCPL to KCREC as Adjustment E-176.2 on Accounting Schedule 10. Adjustment E-176.3 reflects the difference between the test year level and Staff's annualized level of bank fees.

Staff Expert/Witness: Michael Jason Taylor

7. <u>La Cygne Regulatory Asset – Obsolete Inventory</u>

As a result of environmental equipment upgrades that were placed in service at its LaCygne plant during 2015, KCPL proposed to remove from rate base certain spare parts that became obsolete. KCPL also further proposed a write-off of spare parts be amortized over a five-year period once the LaCygne environmental equipment was placed into service. After completion of the LaCygne upgrades, KCPL removed the spare parts from rate base and included an annualized amount of amortization expense in its cost of service for this rate case filing.

In the previous KCPL rate case, Case No. ER-2014-0370, both the Company and Staff removed spare parts from rate base and included an annualized amount of amortization expense in its cost of service for the direct filing (Adjustment E-21.6). In KCPL's 2015 rate case, Staff indicated it expected KCPL to remove from the amortization adjustment any spare parts that can be considered "used and useful" at other KCPL plant facilities. Similarly, Staff also expected KCPL to offset the obsolete inventory adjustment with any residual or scrap value it realizes upon the sale or other disposition of the spare parts. Staff recommended the Commission allow KCPL to amortize, over a five-year period, the obsolete inventory levels determined at the end of the true-up period and track any over-recovery associated with the amortization in order for such over-recovery to be addressed for future treatment in subsequent rate proceedings. In this case, Staff has reflected an annualized amount to reflect the agreed five-year amortization for LaCygne's obsolete spare parts inventory.

Staff Expert/Witness: Cary G. Featherstone

8. <u>Lease Expense</u>

Lease expenses are those costs incurred by KCPL for the leasing of its corporate headquarters and other items. Staff examined these costs for the test year ended December 31, 2015, and update period through June 30, 2016.

Staff verified that the leases currently in effect are planned to remain in effect at the same base rent as what is presently charged to KCPL in the existing lease agreement. Also, Staff confirmed with KCPL that no lease is set to expire as of June 30, 2016 and that none of the current lease terms within each of its agreements will change materially from those in effect during the test year.

When KCPL relocated to its current headquarters, it was allowed 270 days (nine months) of rent-free time, called an abatement period, as part of the lease agreement. In the 2010 rate case, No. ER-2010-0355, KCPL agreed to establish a regulatory liability to account for the rate expense collected in rates, but not incurred during the abatement period. These costs were amortized and returned to ratepayers over a five-year period that ended on April 30, 2016. In the

2014 rate case, No. ER-2014-0370, KCPL agreed to track the amount of any over collections of regulatory liabilities and regulatory assets that were being amortized to cost of service, but had been fully recovered from, or fully returned, to ratepayers. As of the end of the update period, two months of amortizations have been over-returned to ratepayers. At the time of Staff's December 31, 2016, true-up, eight months of this item will have been over-returned; this situation will continue through the effective date of new rates. Pursuant to the tracking agreement, KCPL has tracked the over-returned amount, and proposed to amortize it over three years. Staff has captured the over-returned amount as of June 30, 2016; this adjustment to the test year is reflected in Adjustment E-229-4.

Staff Expert/Witness: Antonija Nieto

9. <u>Insurance Expense</u>

Staff's recommended treatment of Insurance Expense is to treat prepaid insurance as an asset to be included in rate base and amortized ratably over the life of the insurance policy by annualizing the level of insurance expense and allocating an appropriate portion of the expense to KCPL's cost of service. Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events.

Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally paid in advance by utilities, such as the utility payment to the insurance vendor in advance of the policy going into effect. These insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period the insurance is in force. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13 month average balance) is included in rate base, with an annualized level of insurance expense included in rates. Staff witness Michael Jason Taylor discusses the rate base treatment for prepayments in the Rate Base section of Staff's Cost of Service Report.

During the audit, Staff reviewed KCPL's insurance policies for the following forms of insurance:

- Commercial Crime
- Fiduciary Liability

- Directors and Officers (D&O) Liability
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess Fiduciary Liability
- Workers Compensation
- Excess Workers Compensation
- Property
- Cyber-Security Liability
- Labor Management Trust Fiduciary
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated between KCPL and its affiliates, including GMO. KCPL will renew various insurance policies after the update period of June 30, 2016; as part of its True-Up audit, Staff will review these policies and recommend any necessary adjustments. The same methodology used to annualize Insurance Expense as of June 30, 2016 will be used to annualize Insurance Expense for December 31, 2016. The annualized levels for KCPL's portion of the insurance costs are reflected in Adjustments E-208-1 and E-209-3.

Staff Expert/Witness: Antonija Nieto

10. <u>Injuries and Damages</u>

Staff's recommended treatment of injuries and damages is to normalize KCPL's costs associated with injuries and damages, using a three-year average of actual cash payments made by KCPL and paid to entities that had an injury and/or claim against KCPL. Injuries and damages relate to insurance claims that are not covered by insurance policies and usually consist of claims associated with general liability, worker's compensation, and auto liability.

Staff analyzed ten years of data and determined a three-year average of actual cash payments for 2013 through 2015 would be appropriate to normalize KCPL's costs associated with injuries and damages. Based upon Staff's review of prior years' cash payments for claims against KCPL, Staff determined that use of a three-year average was the most appropriate rate allowance for this item based on the widely fluctuating levels of cash payments over time. This normalization of known and measurable changes of the actual cash payments over a multi-year period is consistent with KCPL's method of adjusting injuries and damages in this rate case.

Adjustment E-209.2 reflects a normalized level of costs for injuries and damages.

Staff Expert/Witness: Michael Jason Taylor

11. <u>Property Tax Expense</u>

Staff's recommended treatment of Property Tax Expense is to annualize property taxes based upon property that is in-service on January 1, 2016, by multiplying that property amount by Staff's property tax ratio derived from historical tax payments. Staff adjusted test year property tax expense in order to include in rates the annualized level of 2016 property taxes.

Each year KCPL is billed by each of the local and state taxing authorities that have jurisdiction over KCPL's property. Tax bills for the year are based (assessed) on the property KCPL owns exclusively on January 1 of that calendar year. The property taxes assessed on the property owned as of January 1 of each year are typically not due to the various taxing authorities until December 31 of that same year. The exception is the property taxes assessed in the state of Kansas, where one-half of the year's property taxes are not due until late in the first quarter of the following year. The test year used in this case is the 12-month period ended December 31, 2015, and the true-up period is the 12-month period ended December 31, 2016. Since the test year in this case is December 31, 2015, Staff determined the annualized property taxes based on the property KCPL had in-service on January 1, 2016. Staff applied a property tax ratio based on actual 2015 property tax payments divided by January 1, 2015 taxable plant. In effect, the 2015 tax payments for property taxes develops a relationship to the tax amounts charged to expense to the assessed property—which is always based on the first day of the year. This ratio of property taxes applied to the January 1, 2016 assessed value of the plant provides the amount of property taxes expected to be due at the end of the year in 2016. Because the test year in this case ended December 31, 2015, property tax expenses for 2016 were annualized as of the January 1, 2016 date and this calculation is what Staff expects KCPL's property tax cost to be for 2016. Historically, both Staff and KCPL typically calculate this value by applying the tax rate paid for the previous year to the property owned at the start of the current year.

For the current rate case, Staff obtained from KCPL the total amount of taxable property KCPL owned on January 1, 2016 and then multiplied it by the 2015 property tax ratio, the most current information available. The 2015 property tax ratio is calculated by dividing the total actual amount of property tax paid by KCPL in 2015 by the total cost of the taxable property owned on January 1, 2015. Since the actual property taxes paid in 2015 was based on the assessments of the January 1, 2015 property, this ratio applied to the January 1, 2016 plant estimates the amount of property taxes that will be due at the end of 2016. The estimated 2016 property tax was then increased by KCPL's 2016 contractual payments in lieu of taxes ("PILOTs") applicable to non-taxable property.

Staff recommends this method of calculation as providing the best available information, since it relies on the actual January 1, 2016 balance of KCPL's property and uses the most recent, known effective tax rate (2015). This method does not attempt to estimate or project any change in the rate of taxation for 2016 that is not known as of the update period of June 30, 2016.

Staff's approach is consistent with that taken previously, which received several favorable rulings from the Commission in prior cases, notably in KCPL 2006 rate case. In its *Report and Order* issued in Case No. ER-2006-0314, the Commission stated the following:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-service balance to the amount of property taxes paid in 2005. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.

Adjustment E-257.1 reflects Staff's annualized property taxes.

Staff Expert/Witness: Matthew R. Young

12. <u>Rate Case Expense</u>

Rate case expense is the sum of the costs a utility incurs in preparing and filing a rate case. In the instant case, KCPL has incurred expenses in conjunction with legal counsel, regulatory consulting, and outside consultants. Staff recommends assigning KCPL's discretionary rate case expense to both ratepayers and shareholders. The amount of rate case expense assigned to shareholders is based upon the ratio of Staff's recommended rate increase to KCPL's requested rate increase. This ratio will be updated throughout the remainder of the case and will ultimately be based on the ratio of the Commission approved rate increase to KCPL's requested rate increase.

a. Background

Generally, Staff divides rate case expense over the period of time it estimates will pass before the utility's next rate case and includes an annual amount in the utility's revenue requirement. Typically, this cost is not "amortized" for ratemaking purposes, and the utility's recovery of this expense in rates is not tracked against its actual rate case expense for consideration of over or under recovery.

However, when KCPL's Regulatory Plan contemplated four rate case filings over less than four years, Staff did not oppose the "defer and amortize" or "vintage accounting" approach that KCPL requested in each of the Regulatory Plan rate cases—Case Nos. ER-2006-0314, ER-2007-0291, ER 2009-0089, and ER-2010-0355. For the rate case expenses for each of these cases, as adjusted, Staff used a "defer and amortize" approach to calculate the associated revenue requirement to be included in the following rate case. Under this special "defer and amortize" approach to rate case expense, KCPL deferred the rate case expenses for each rate case as a separate vintage deferral and amortized each of those vintage deferrals over a multi-year period. The rate case expense KCPL incurred after the end of the true-up period in one case was deferred until the next rate case for consideration of recovery.

In Case No. ER-2012-0175, Staff returned to its more typical normalization approach for establishing an ongoing level of rate case expense to include in KCPL's revenue requirement because the Regulatory Plan rate cases were completed. However, an amortization of rate case expenses incurred for the 2010 rate case was not completed until September, 2015. In the current case, Staff has removed this amortization expense from the test year to reflect the full recovery of deferred rate case expense.

b. Recommendation

In addition to recognizing the end of the amortizations of the rate case expenses KCPL incurred for the four rate cases addressed in its Regulatory Plan, Staff is recommending the Commission approve a normalized amount of rate case expense based on KCPL's incurred costs multiplied by the ratio of the Commission approved rate increase to the Company's requested increase. Staff recommends that any subsequent over or under-recovery by KCPL of the ordered amount should not be recognized in future cases.

Since rate case expense is typically end-loaded (i.e. a material amount of cost is incurred near the end of the case, i.e. evidentiary hearings), Staff's examination of rate case expense resulting from this case is not complete. Staff will continue to examine this case's rate case expense and update total rate case expense until a cut-off point is determined.

Staff Adjustment E-224.4 reflects Staff's recommended rate case expense, calculated as described above. Staff Adjustment E-224.2 removes the 2010 Rate Case amortization from the test year, and Staff Adjustment E-224.3 removes test year rate case expense incurred in Case No. ER-2014-0370.

c. Rate Case Expense Sharing Recommendation

Rate case expense can be defined as all incremental costs incurred by a utility directly related to an application to change its general rate levels. These applications are usually initiated by the utility, but rate case expenses may also be incurred as a result of the filing of an earnings complaint case by another party. The largest amounts of rate case expense usually consist of costs associated with use of outside witnesses/consultants and outside attorneys hired by the utility to participate in the rate case process.

Generally, utility management has a high degree of control over rate case expense. Attorneys, consultants, and other services can either be provided by in-house personnel or can be procured by an outside party. Some Missouri utilities employ in-house counsel and primarily utilize internal labor to process rate filings; therefore, the use of outside attorneys in rate proceedings is not always necessary. However, KCPL currently procures outside counsel, in addition to in-house attorneys who have significant prior experience in Missouri rate proceedings. Rate case expenses generally do not include internal labor costs, as those are included in the cost of service through the payroll annualization and are not incremental expenses resulting from the rate case process.

During rate proceedings, and generally in the utility regulatory process, there are four broad categories of costs involved:

1) The cost incurred by the Commission for itself and its Staff;
2) The cost incurred by the Public Counsel;
3) The cost incurred by interveners in Commission proceedings; and
4) The cost incurred by the utility in the regulatory process.

Category 1 is the cost incurred by the Commission. This includes all operating expenses, salaries, wages, and benefits of the Commission and its Staff. The Commission's operating expenses are limited to the amount the Missouri General Assembly appropriates for that purpose. An annual amount of operating expenses are assessed by the Commission and paid by the utilities it regulates. The utility, in turn, passes on this expense to its ratepayers through the rate case process. The utility is not charged the direct cost of processing its filings or regulating company specific activities. KCPL is charged based on an assignment of the Commission's budget for regulation of the electric industry, with this amount allocated to KCPL based on the percentage of KCPL regulated revenues of the total electric regulated revenues in Missouri.

Category 2 is the cost incurred by Public Counsel. Public Counsel represents the public and interests of utility customers in proceedings before the Commission. An amount for Public Counsel's annual operating expenses is appropriated by the Missouri General Assembly which is sourced from the Commission's assessment.

Category 3 is the cost incurred by interveners in Commission proceedings. Interveners may be involved in Commission proceedings for a variety of reasons, but most frequently related to revenue requirement and rate design issues raised in general rate proceedings. Some intervening parties represent large individual utility customers or groups of customers. There are several interveners in this case, some of whom have retained their own counsel and experts to review KCPL's rate increase. Each intervener is responsible for its own rate case expenses.

Category 4 is the cost incurred by the utility in the regulatory and rate setting process. The Commission has generally allowed utilities to pass through to ratepayers the full amount of normalized and prudently incurred rate case and regulatory expenses to its rate payers in the rate setting process. When utilities are allowed to pass full rate case costs to ratepayers, category 4 (the utility's cost) is the only category of rate case participants in the rate case process that does not face an inherent limit in the amount of rate case expense it chooses to incur. The other three categories of rate case participants are limited in the amounts of rate case expense they can incur by the budgetary decisions of the General Assembly or by the willingness of the intervening parties to fund rate case activities. However, with full rate case expense recovery, the utilities are free to plan their rate case activities with the knowledge that the associated cost of those activities is highly likely to be passed on to a third party; i.e., its customers.

Both ratepayers and shareholders benefit from the rate case process. Customers have a vested interest in ensuring that they pay just and reasonable rates for safe and adequate service and shareholders have a vested interest in ensuring an opportunity to receive a reasonable return on their investment. If the utility determines that the rates it charges its customers are inadequate, the rate making process before the Commission is the sole venue to remedy that situation. However, utility regulation in Missouri is, at least in part, premised upon an assumption that the utility is not likely in all circumstances to act in the best interests of its customers. This assumption points out the inequity of having customers finance a utility's efforts to increase rates that may be ultimately found by the Commission to be excessive or unreasonable in amount.

The practice of allowing a utility to recover all, or almost all, of its rate case expense from customers creates a disincentive to control rate case expenses incurred by the utility. For all other parties to the rate case process, the funds spent are ultimately limited by a budget and financial restraints. Having significant financial resources to fund rate case activities combined with the ability to pass through the entire amount of expenses creates what can be perceived as an unfair advantage over all other parties in the rate case process.

Some expenses incurred for which the utility has a high level of discretion and control are not recovered by the utility in the ratemaking process, even if such expenditures are considered "prudent" from the perspective of the utility. For example, charitable donations have historically not been an includible expense in the cost of service. Donations are defined as discretionary amounts paid to individuals or organizations for charitable reasons, with no direct business benefit. While the utility may believe it has a responsibility to be a "good corporate citizen," charitable contributions, if included in the cost of service, would equate to an involuntary contribution by the rate payer. Costs associated with political activities (lobbying) are another type of cost usually not allowed to be included in customer rates. These are costs not necessary to the provision of utility service in Missouri.

On April 27, 2011, the Commission issued an Order establishing Case No. AW-2011-0330, and within this docket directed its Staff to investigate the Commission's current rules and practices regarding recovery of rate case expense in rates by Missouri utility companies. In particular, the Commission asked whether the current policy of generally allowing rate recovery of the entire amount of a utility's incurred rate case expense should be changed either by assigning some portion of these costs to the utility's shareholders, or instituting an overall "cap," or limit, on the amount of recovery of rate case expense in rates by utilities. The Commission stated its concern over rate case expense issues was related to testimony presented in recent rate cases and the recent escalation in the amount of claimed rate case expenses by Missouri utilities. As part of its investigation into these matters, Staff was directed to investigate the practices of other public utility commissions regarding rate recovery of rate case expense.

Several alternative approaches were discussed by Staff for the Commission's consideration in its Report in Case No. AW-2011-0330 that was filed in September 2013. One of the options for rate case expense recovery presented in Staff's Report was tying a utility's percentage recovery of rate case expense to the percentage of its rate increase request it is successfully awarded by the Commission.

Staff presented this sharing mechanism, along with other alternatives in the Cost of Service report and testimony in Case No. ER-2014-0370, KCPL's most recent rate case. The Commission ordered a sharing of rate case expenses in its Report and Order in Case No. ER-2014-0370, on page 72:

> The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One method to encourage KCPL to limit its rate case expenditures would be to link KCPL's percentage recovery of rate case expense to the percentage of its rate increase request the Commission finds just and reasonable. The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in this rate case.
>
> The Commission concludes that KCPL should receive rate recovery of its rate case expenses in proportion to the amount of revenue requirement it is granted as a result of this Report and Order, compared to the amount of its revenue requirement rate increase originally requested. This amount should be normalized over three years. The Commission also finds that it is appropriate to require a full allocation to ratepayers of the expenses for KCPL's depreciation study, recovered over five years, because this study is required under Commission rules to be conducted every five years. [footnotes omitted]

In accordance with the Commission's Report and Order, Staff recommends the same rate case expense sharing with regard to KCPL's rate case expense in this case.

Staff concludes that this sharing of expenses is appropriate in this proceeding for the following reasons:

1) This sharing mechanism was ordered by the Commission in the recent KCPL rate case, Case No. ER-2014-0370;
2) Rate case expense sharing creates an incentive, and eliminates a disincentive, on the utility's part to control rate case expense to reasonable levels;
3) There is a high likelihood that some positions advocated for by utilities through the rate case process will ultimately be found by the Commission to not be in the public interest; and
4) Both ratepayers and shareholders benefit from the rate case process; the ratepayer receiving safe and adequate service at a just and reasonable rate, and the shareholder receiving an opportunity to receive an adequate return on investment.

Staff intends to examine sharing options for rate case expense in future general rate proceedings for major utilities, and may advocate a different approach to sharing, or different sharing percentages, depending upon the circumstances of each individual filing.

Staff Expert/Witness: Matthew R. Young

13. <u>Depreciation Study</u>

Depreciation study expense is the cost associated with obtaining and supporting the depreciation study required in Commission rule 4 CSR 240-3.160(1)(A). This rule states that, "any electric utility which submits a general rate increase request shall submit…":

> Its depreciation study, database and property unit catalog. However, an electric utility need not submit a depreciation study, database or property unit catalog to the extent that the commission's staff received these items from the utility during the three (3) years prior to the utility filing for a general rate increase or before five (5) years have elapsed since the last time the commission's staff received a depreciation study, database and property unit catalog from the utility.

Staff's interpretation of this rule is that a depreciation study has a useful life of five years. Consequently, Staff obtained the most recent cost incurred by KCPL to retain a consultant for the purposes of conducting a depreciation study[82], including the expense to update the study[83] as needed. The net cost was included in the cost of service as a five-year normalized expense reflected in Staff adjustment E-219.2.

Staff Expert/Witness: Matthew R. Young

14. Regulatory Assessments

a. Public Service Commission Assessment Fee

The Public Service Commission Assessment ("PSC Assessment") is an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs for regulating those utilities. KCPL's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2017) on information obtained from the Commission's records. The updated KCPL PSC Assessment was compared to the PSC Assessment amount included in KCPL's test year as of December 31, 2015, to form the basis for the adjustment in Staff's accounting schedules. Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment E-217.1.

Staff Experts/Witnesses: Antonija Nieto and Karen Lyons

b. FERC Assessment

KCPL is also assessed a regulatory fee from the Federal Energy Regulatory Commission ("FERC"). Staff included an annualized level of the FERC assessment based on the 12 month period ending June 30, 2016. Staff's adjustment is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment E-216.1.

Staff Experts/Witnesses: Antonija Nieto and Karen Lyons

15. Customer Deposits – Interest Expense

Staff's recommended treatment of interest expense on customer deposits is to include the interest expense in the expense portion of the revenue requirement calculation, since customer deposits were deducted in the calculation of rate base. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base - Schedule 2

[82] Statement of work between GPES and Gannett Fleming for depreciation study dated June 20, 2014.
[83] Statement of work between GPES and Gannett Fleming for update of generation study dated April 29, 2016.

(see discussion in the Rate Base section of this report for Customer Deposits included in rate base). For this calculation, Staff used the method outlined in KCPL's tariff which is to use the customer deposit balance to be included in rate base, and then multiply that number by the most current prime interest rate published in the Wall Street Journal (3.50) plus 100 basis points, for a total of 4.50%. The amount of interest relating to customer deposits has been included as an adjustment to the Income Statement - Schedule 9. The Commission should base its awarded revenue requirement on Staff's recommended amount of interest relating to customer deposits by including the customer deposit interest expense amount calculated by Staff as an expense adjustment to KCPL's income statement. Adjustment E-173.1 and E-173.2.

Staff Expert/Witness: Michael Jason Taylor

16. <u>Depreciation - Clearing</u>

During the test year, KCPL incurred depreciation for transportation equipment that was charged to expense through a clearing account. Because depreciation expense is accounted for in Staff's Accounting Schedule 5, Staff made an adjustment to remove the depreciation amount booked to the clearing account, Adjustment E-232.1.

Staff Expert/Witness: Karen Lyons

17. <u>Economic Relief Pilot Program</u>

The Economic Relief Pilot Program ("ERPP" or "Program") offered by KCPL was established to deliver energy affordability benefits to KCPL's qualifying low-income customers. Low-income customers are defined as having an annual household income no greater than 200 percent of the Federal Poverty Level ("FPL"). The FPL is the set minimum amount of gross income that a family needs for food, clothing, transportation, shelter and other necessities. The level is determined by the Department of Health and Human Services and is used as one of the criteria in determining eligibility in low-income programs.

The Program is designed to provide up to $65 as a bill credit for up to 1,500 participants monthly. In Case No. ER-2012-0174, total ERPP annual funding was set at $630,000 with one-half of the funding contributed from shareholders and the other half from ratepayers. In Case No. ER-2014-0370, ERPP total annual funding was doubled to $1,260,000. In this rate case the Company is proposing to lower the annual funding contributed by ratepayers to $589,984,

($585,000 for the program and $4,984 to the Salvation Army for administration of the program). The amount is matched dollar for dollar by shareholder funds ($1,179,968 total funding).

Staff compared Program funding and Program costs from January 26, 2013, the effective date of rates ordered in a prior KCPL rate case, Case No. ER-2012-0174, , through June 30, 2016. The currently unspent funding amount from Case No. ER-2012-0174 is $140,700, and from Case No. ER-2014-0370 is $386,145; for a total of $526,845 of unspent funds. The 50% ratepayer share of those unspent funds is $270,000.

Staff's recommendation is to continue the amount of program costs filed in Company witness Ronald A. Klote's direct testimony workpaper CS-44F for ratepayer expenditures of $589,984. Staff further recommends, due to the accumulation of over a half-million dollars in unspent funds, that ratepayer funding be set at $500,000 annually and $89,984 be funded annually from the balance of unspent funds.

Staff also recommends KCPL expand administration of the Program to other community action agencies within its service territory to help achieve the 1,500 monthly participant level approved in Case No. ER-2014-0370. Salvation Army is the only non-profit social service agency currently administering the Program, which only averages a monthly participant level of 1,215.

Staff Expert/Witness: Kory Boustead

a. Accounting Treatment

In a previous KCPL rate case, Case No. ER-2012-0174, KCPL shareholders and ratepayers were ordered by the Commission to each provide an equal amount of funding for ERPP expenditures. Beginning February 2013, the effective date of new rates from Case No. ER-2012-0174, KCPL started collecting ERPP ratepayer funding through base rates. ERPP ratepayer funding was increased in KCPL's most recent case, Case No. ER-2014-0370, as described by Staff witness Kory Boustead in the section above. Staff adjustment E-180.4 increases the test year ERPP expense to include ERPP ratepayer funding, offset by unspent ERPP funding, at the level recommended by Staff witness Boustead (above).

In Case No. ER-2012-0174, a vintage of deferred ERPP costs was established and amortized beginning with the effective date of rates in that case. Because the amortization of this vintage has ended, Staff made adjustment E-180.5 to remove the amortization expense from the test year.

Staff Expert/Witness: Matthew R. Young

18. Income Eligible Weatherization Program (formally Low Income Weatherization Program)

KCPL's Income-Eligible Weatherization Program[84] ("Program") was initially established in 2007 as one of several demand response, efficiency, and affordability programs which were implemented as a result of the Stipulation and Agreement approved by the Commission on August 23, 2005 in File No. EO-2005-0329.[85] On July 6, 2014, KCPL's Missouri Energy Efficiency Investment Act ("MEEIA") demand-side management ("DSM") programs and demand-side investment mechanism ("DSIM") rider became effective in Case No. EO-2014-0095. On that date, KCPL's eligible Program costs were recoverable under the DSIM Rider.

On page 102 of the Commission's September 2, 2015 *Report and Order* for Case No. ER-2014-0370[86] the Commission offers the following guidance on the recovery of Program costs:

> Since the Program is an important service that benefits low-income residents, the Commission considers continuity of the Program to be a valuable goal. To avoid any continuity problems in the future, the Commission finds that collecting Program funds through base rates to be preferable. This will also provide for consistency across the state as most other regulated electric utilities collect weatherization funds through base rates. The Commission concludes that KCPL should resume recovery of low-income weatherization program costs in base rates following the conclusion of KCPL's MEEIA Cycle 1 and cease recovery of these costs in future MEEIA applications. With regard to any surplus Program funds recovered previously through base rates, the unexpended low-income weatherization program funds collected through KCPL's base rates should be used to offset any expenditures relating to the Program.

[84] The Program was originally called Low-Income Weatherization when it was first designed.
[85] File No. EO-2005-0329 is also referred to as the Kansas City Power & Light Company Experimental Regulatory Plan.
[86] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2014-0370.

In KCPL witness Ronald A. Klote's direct testimony states, "KCP&L does not plan to recover Income Eligible Weatherization Expense until the liability account gets to a reasonable level. We are proposing to use funds set aside in the account for the present time and set the annualized level to zero."[87] In Mr. Klote's direct testimony workpaper Adjustment CS-98 MEEIA Expense, there is a notation "Propose to use funds set aside in the liability account for the present time."

Staff data request 0175 requests the budget and expenditures of the Program for the years 2014-2016. According to KCPL's response to data request 0175, during Program year 2014 the annual program budget was $573,888 with an annual expenditure of $258,987, allowing 28 homes to be weatherized and leaving a remaining balance of $314,901. It was during this program year the Missouri Department of Economic Development, Division of Energy, appointed the United Services Community Action Agency ("Agency") to replace The City of Kansas City as the weatherization agency in the KCPL service territory. There was a significant ramp up period for the Agency after the change accounting for a significant portion of the unspent funds.

In Program year 2015 the annual budget was $549,817 with $481,840 spent to weatherize 127 homes and leaving a remaining balance of $67,977. For the current program year 2016, the annual budget is $573,888. As of September 26, 2016, $357,520 has been used for weatherization[88], leaving unspent funds of $216,368 available through December 31, 2016.

In preparation for a recommendation on funding, Staff auditor Matthew Young requests further data in Data Request 0293 in regards to the total unspent funding amount in the liability account. KCPL's response indicates that KCPL's liability account for the Program has a balance of $1,296,861.94 as of September 30, 2016. Assuming that KCPL's Program costs are $573,888 annually, it will take over 2.25 program years to utilize the unspent funding level.

Staff recommends the Commission reject KCPL's proposal to not fund the Income-Eligible Weatherization program through base rates at this time. Instead, to allow the unspent funding level to decrease to a reasonable level, Staff recommends the Commission approve continued funding of the Program through rates at a reduced level. A reduced level of ratepayer

[87] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2016-0285 *(Direct Testimony of Ronald A. Klote,* filed July 1, 2016*)* page 53, lines 11-13.
[88] Staff Data Request No. 0175.

funding will allow KCPL to utilize the balance of unspent funds if the targeted annual expenditures of $578,888 is achieved.

Staff Expert/Witness: Kory Boustead

a. Accounting Treatment

When the Program was established in 2007, KCPL deferred the Program costs and recovered them through amortizations in later rate cases. Beginning in Case No. ER-2012-0174, the funding for the Program was approved to be funded through rates at a level of $573,888 per year. The same level of funding was included in the rates resulting from KCPL's most recent rate case, Case No. ER-2014-0370. Staff compared the total funding KCPL collected through rates for the Program from February 1, 2013 (date ratepayers began providing Program funding) through June 30, 2016 and compared the total with the funds spent over the same time period. The comparison yielded a balance of unspent Program funding that was earmarked for Program expenditures. Staff has included the Program liability as of June 30, 2016 as a deduction to rate base.

Staff adjustment E-181.2 increases test year Program expense to match the level of funding recommended by Staff witness Kory Boustead above.

Staff Expert/Witness: Matthew R. Young

19. Regional Transmission Organization ("RTO") Administrative Fees

SPP is a not-for-profit, RTO entity which maintains functional control over portions of the transmission assets of its members transferred to it and provides transmission services through its Federal Energy Regulatory Commission ("FERC") approved Open Access Transmission Tariff ("Open Access Tariff" or "OATT"). SPP's costs must be recovered from its users (transmission customers, which, in this case, are utility companies such as KCPL, GMO, The Empire District Electric Company, Westar Energy, Inc. and other electric companies). Consequently KCPL pays SPP an administration charge for performing transmission functions on its behalf.

Under its Open Access Tariff, SPP establishes a rate for its administration charge annually that enables it to recover 100% of its total annual administrative costs for RTO functions, subject to a rate cap. The rate cap serves as a limit on the annual administration charge in order to provide SPP customers a level of certainty and predictability regarding SPP's year-to-year administrative costs. SPP's administrative rate cap is currently $.39 per MWh. Although the administrative fee rate cap is still in effect, on December 8, 2015, SPP's Board of Directors approved SPP's Finance Committee recommendation to reduce the administrative fee to $.37 per MWh for the calendar year 2016. The following chart reflects SPP's historical administrative fee rate for the period of 2006-2016.

Historical SPP Administrative Fee per MWh										
Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate	$.19	$.19	$.17	$.195	$.210	$.255	$.315	$.381	$.39	$.37

Staff annualized SPP administration fees based on the administrative rate of $0.37 per MWh effective January 1, 2016. Included in the annualized amount are North American Electric Reliability Corporation ("NERC") fees and Midcontinent Independent System Operator, Inc. ("MISO") RTO administrative fees for point-to-point transmission. Staff's adjustments for RTO Administration fees are identified on Schedule 10 of Staff's Accounting Schedules, Adjustment E-125.2 and E-132.1.

Staff Expert/Witness: Karen Lyons

20. <u>Transmission Expense-FERC Account 565</u>

KCPL and GMO are members of the SPP. In 2004, SPP became a RTO responsible for ensuring reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices.[89] Prior to 2006, KCPL had full functional control over its transmission system that served its retail customers within its service territory. In Case No. EO-2006-0142, KCPL filed an application with the Commission to transfer functional control of its transmission facilities to SPP. Most of the parties to that case entered into a Stipulation and Agreement on February 24, 2006, and the Commission approved the Stipulation and Agreement by Order effective on June 23, 2006. The transfer of functional control of KCPL's transmission system to SPP was finalized upon the approval by the FERC on October 1, 2006.

[89] Market Protocols for SPP Integrated Marketplace, page 60.

As a transmission customer of SPP, KCPL is charged for point-to-point, base-plan-zonal, and region-wide transmission costs that are booked to FERC Account 565. Point-to-point transmission costs are billed based on Schedule 7 and Schedule 8 of SPP's Open Access tariff. Base-plan-zonal charges and region-wide charges are billed based on Schedule 11 of the Open Access tariff.

Base-plan-zonal and region-wide costs are a result of transmission upgrades in the SPP region. The transmission upgrades are directed by SPP's Transmission Expansion Plan to ensure the reliability of the transmission system for SPP's members.[90] The costs of base-plan and region-wide projects are allocated to the SPP region based on the voltage of the project. The allocation method is referred to as the Highway-Byway method and is shown in the following table:

SPP Base Plan Highway-Byway Allocation Method		
Voltage	Regional (SPP region)	Zonal (KCPL region)
300 kV and Above	100%	0%
100-300 kV	33%	67%
Below 100%	0%	100%

The costs allocated to the SPP region are then allocated to SPP transmission customers based on a load share. The load share ratio is developed using the transmission customer's network load divided by the SPP total load. KCPL's current load ratio share, on a total company basis (Missouri and Kansas), is 7.35%.

Staff analyzed KCPL's actual transmission expenses for the period of 2009 through 2015. KCPL's transmission expenses for the 12-month period ended December 31, 2015, have **________________ ** since 2009. The following chart reflects KCPL's historical transmission expenses for the period of 2009-2015.

continued on next page

[90] SPP OATT Tariff.

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Based on Staff's analysis, KCPL's transmission expenses have significantly increased during those seven years. Staff also analyzed the 12 month period ending June 30, 2016 and determined the upward trend continued during this period. Consequently, Staff included an annualized level of transmission expense based on the 12-month period ended June 30, 2016, the most recent costs available. Staff's adjustment for transmission expense is identified on Schedule 10 of Staff's Accounting Schedules, Adjustment E-129.1. Since KCPL's transmission expense has significantly escalated, Staff will review this adjustment in its True-Up audit based on updated events and cost information.

In October, Staff was notified by KCPL that beginning in November 2016, KCPL will incur costs from SPP that are referred to as "Z2 credits." According to KCPL, SPP purportedly has been delayed since 2008 in implementing revenue crediting for certain transmission service that could not have been provided "but for" directly assigned network upgrades, under Attachment Z2 of the SPP Tariff. According to KCPL, SPP has evidently stated that as a result

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of the necessary software becoming fully operational, it planned to begin collecting and distributing credit payment obligations by the fourth quarter of 2016. Although KCPL has not provided specific details on how the financial impact of these costs will be treated for ratemaking purposes, Staff anticipates KCPL's recommendation on this point in the true-up.

Staff Expert/Witness: Karen Lyons

21. <u>Missouri Flood Amortizations</u>

a. 2011 Missouri River Flood Incremental Non-Fuel Operations & Maintenance ("NFOM") Expense

The Commission authorized KCPL to defer the incremental $1.4 million Missouri jurisdictional NFOM expense related to the 2011 Missouri flood into a regulatory asset with amortization over 5 (five) years beginning with the effective date of rates in Case No. ER-2012-0174.[91] The test year ending December 31, 2015 includes a full 12 months of amortization related to these deferred expenses; therefore, no adjustment is necessary. The amortization is included in the test year of expenses in Staff Accounting Schedule 9 – Income Statement.

Staff Expert/Witness: Keith Majors

b. 2011 Missouri River Flood Insurance Reimbursement

KCPL received insurance proceeds in March and August of 2013 related to the impact of the 2011 Missouri River flooding. The Commission authorized KCPL to defer these proceeds and return them to customers over 3 (three) years beginning with the effective date of rates in Case No. ER-2014-0370.[92] Staff Adjustments E-5.2 and E-202.1 in Schedule 10 – Income Statement reflect this amortization.

Staff Expert/Witness: Keith Majors

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[91] January 26, 2013.
[92] September 29, 2015.

22. <u>Transition Costs</u>

a. Aquila, Inc. Acquisition Amortized Transition Costs

Pursuant to the Commission's *Report and Order* in Case No. ER-2010-0355, KCPL began amortizing deferred Aquila, Inc. acquisition transition costs at the effective date of rates in that case on May 4, 2011. These transition costs were deferred pursuant to the Commission's *Report and Order* in Case No. EM-2007-0374. These deferred transition costs include non-executive severance costs for employees terminated, facilities integration costs, and incremental third-party and other non-labor expenses incurred as a result of the acquisition.

KCPL filed Case No. ER-2016-0285 on July 1, 2016. This date is subsequent to January 1, 2015, the date which KCPL agreed to not seek further recovery of amortized transition costs, pursuant to the *Non-Unanimous Stipulation and Agreement as to Certain Issues* filed October 19, 2012 in Case No. ER-2012-0174. KCPL-GMO Common Issues - Issue II.7 Acquisition Transition Costs, was resolved on page 5 pursuant to the following terms:

> The five-year amortization of acquisition transition costs (KCPL annual amount of $3.8 million, GMO amount of $4.3 million — MPS $3.5 million and L&P $0.8 million) shall continue; however, KCPL and GMO shall not seek recovery of acquisition transition costs in any general electric rate case filed after January 1, 2015. Total Missouri jurisdictional transition costs related to the 2008 acquisition of Aquila are capped at the December 31, 2010 amount of $41.5 million. No other transition costs related to the 2008 acquisition of Aquila will be deferred for recovery in any general electric rate case.

Ordered Paragraph 1 of the Commission's January 9, 2013 Report and Order in File No. ER-2012-0174 incorporated into said Report and Order the October 19, 2012 *Non-Unanimous Stipulation and Agreement as to Certain Issues.*

Staff removed the test year amortized transition costs. These adjustments are included in KCPL's miscellaneous adjustments referenced as "CS-11", which is further described by Staff witness Matthew R. Young. Staff has reflected these miscellaneous in Staff Accounting Schedule 10.

Staff Expert/Witness: Keith Majors

23. <u>Demand-Side Management Cost Recovery</u>

a. Opt Out Treatment

It appears KCPL calculated Pre-MEEIA customer opt-outs of DSM programs with data ending in December 2015. Staff performed a similar calculation using data through June 30, 2016; therefore Staff made an adjustment to data used by Staff witness Matthew R. Young in his amortizations as discussed below.

Staff Expert/Witness: Michael L. Stahlman

b. Rate-Making Treatment for the DSM Program Cost

In its Report and Order in Case No. ER-2010-0355, with regard to how past and future demand-side management ("DSM") costs should be treated, the Commission stated:

> One area of agreement is that the ―old regulatory assets (Vintages 1, 2, and 3) should be governed by the previous decisions to amortize those regulatory asset accounts over a ten-year period and that amortization period should not change. The Commission also agrees and directs that Vintages 1, 2, and 3 continue to be amortized over a ten-year period.
>
> KCP&L agrees with MDNR regarding the treatment for ―future investments. The Commission agrees as well and will direct that DSM program costs for investments made from December 31, 2010, until a future recovery mechanism is in place [Vintage 5] shall be placed in a regulatory asset account and amortized over six years with a carrying cost equal to the AFUDC rate applied to the unamortized balance
>
> With regard to the ―current investments, it would be inconsistent with previous Commission orders to authorize a six-year amortization for the current investments (Vintage 4). The Commission determines that these Vintage 4 investments should continue to be amortized over a ten-year period.
>
> The Commission determines that the unamortized balances of the regulatory asset accounts shall be included in rate base for determining rates in this case.

In adjustment E-181.1 in this case, Staff included the DSM vintages in the revenue requirement consistent with the Commission's order above by including the unamortized balances for Vintages 1-7 in its Rate Base Accounting Schedule 2 and by including the annual amortization for each vintage based on a ten-year amortization for Vintages 1-4, a six-year amortization for Vintages 5-6[93] and a recommended six-year amortization for Vintage 7.

c. Accounting Treatment for Expiring Vintages

In reviewing the amortization schedules for each vintage, Staff noted that Vintage 1 will be fully amortized on December 31, 2016, the true-up date in this case. Vintage 2 will be fully amortized within one year of the expected conclusion of the current rate case and Vintage 5 within two years. Once the vintages are fully amortized, KCPL will be collecting funds in rates for expenses it is no longer incurring. Staff recommends that once amortization of a vintage is complete, KCPL apply the funds that will continue to be collected through rates (for the completed amortizations) to the unrecovered amounts of the DSM vintage scheduled to expire next. This accounting treatment is appropriate since all seven (7) existing vintages are nearly identical in nature except for the timing in which the DSM costs were incurred. Since the approval of KCPL's regulatory plan on July 28, 2005, KCPL has been managing energy efficiency programs, demand response programs, and affordability programs. The type of programs included in the deferred DSM costs has not substantially changed since 2005 and, therefore, Staff recommends that the funds collected for each vintage should not be earmarked for that particular vintage, but pooled to reimburse KCPL for the deferred costs expeditiously.

Since July 6, 2014, when KCPL's MEEIA programs became effective as a result of Case No. EO-2014-0095, a majority of Pre-MEEIA DSM program costs have been shifted to the Company's MEEIA recovery mechanism and the remaining DSM costs have virtually ceased. Staff recommends that KCPL no longer defer DSM costs into a regulatory asset for future recovery after the true-up date in this case, and DSM vintage 7 be the final DSM vintage.

Staff Expert/Witness: Matthew R. Young

24. <u>Amortization of Regulatory Assets and Liabilities</u>

Both regulatory assets and liabilities are authorized by the Commission to be deferred and included in rates to be returned to or received from ratepayers. In the 2014 KCPL Rate Case (File No. ER-2014-0370), the signatories to the *Partial Non-Unanimous Stipulation and*

[93] Vintage 6 amortized over 6 years per ER-2014-0370.

Agreement as to Certain Issues filed July 1, 2015, agreed to the following concerning regulatory assets and liabilities:[94]

> **I. PROSPECTIVE TRACKING OF REGULATORY ASSET AND LIABILITY RECOVERY**
>
> In each future KCP&L general rate case, the Signatories agree that the balance of each amortization relating to regulatory assets or liabilities that remains, after full recovery by KCP&L (regulatory asset) or full credit to KCP&L customers (regulatory liability), shall be applied as offsets to other amortizations which do not expire before KCP&L's new rates from that rate case take effect. In the event no other amortization expires before KCP&L's new rates from that rate case take effect, then the remaining unamortized balance shall be a new regulatory liability or asset that is amortized over an appropriate period of time. For example, the Demand Side Management amortizations, once fully recovered, will be used to offset (reduce) other vintages of DSM amortizations, each reducing other vintages as those become fully recovered and, in the event no other vintages remain to be amortized, the Demand Side Management amortizations will be applied to other amortizations that do not end before new rates take effect.

The only regulatory asset and liability amortization subject to this prospective tracking that has ended since the true-up cutoff in the 2014 Rate Case is the amortization of a lease abatement. The lease abatement amortization relates to the rent abatement period that occurred when Great Plains Energy, Inc., including KCPL, moved its headquarters from one location in downtown Kansas City to its current location in downtown Kansas City. This regulatory liability was authorized in the 2010 Rate Case (File No. ER-2010-0355) with amortization over five (5) years beginning May 4, 2011.

There are amortizations that still have balances and are currently being collected in the cost of service ("COS"). In some cases, a "vintage" as referenced in the above stipulation, has been fully collected. Pursuant to the stipulation referenced above, the over-collections have been used to offset vintages of tracked costs that are still being amortized. All of these items are discussed in more detail in other sections of Staff's COS Report.

[94] The Commission issued an *Order Approving Stipulation and Agreement Regarding Certain Issues* on July 17, 2015.

- 2011 Missouri River Flood Non-Fuel O&M – Staff Expert/Witness: Keith Majors
- 2011 Missouri River Flood Insurance Reimbursement–Staff Expert/Witness: Keith Majors
- Transource Missouri Account Review–Staff Expert/Witness: Keith Majors
- Demand Side Management Advertising Costs– Staff Expert/Witness: Matthew R. Young
- Surface Transportation Board Litigation– Staff Expert/Witness: Karen Lyons
- LaCygne Obsolete Inventory– Staff Expert/Witness: Cary G. Featherstone
- Cost of Removal Deferred Income Tax– Staff Expert/Witness: Keith Majors
- Wolf Creek Mid-Cycle Outage– Staff Expert/Witness: Michael Jason Taylor
- Wolf Creek Nuclear Refueling Outage 18– Staff Expert/Witness: Michael Jason Taylor
- Renewable Energy Standards– Staff Expert/Witness: Matthew R. Young
- Economic Relief Pilot Program– Staff Expert/Witness: Matthew R. Young
- Iatan 2 O&M Tracker– Staff Expert/Witness: Michael Jason Taylor

Pursuant to the stipulation referenced above, KCPL agreed to track any overcollections associated with any amortization established, including the list above, to be used as offsets to other amortizations which do not expire before new rates from a subsequent KCPL rate case take effect.

Staff Expert/Witness: Keith Majors

25. <u>Allconnect Revenues and Expenses</u>

Pursuant to the Commission's *Report and Order* in File No. EC-2015-0309, Staff has included an adjustment to restore the revenues and expenses related to the Allconnect Direct Transfer Service Agreement. The Commission ordered all expenses and revenues associated with the Allconnect relationship to be brought "above the line" and included in regulated cost of service, on page 22 of the *Report and Order* in that case:

> The Commission finds and concludes that the revenue and expense associated with the Allconnect relationship should be treated as regulated revenue and expense and brought "above the line." While the services Allconnect offers are not regulated by this Commission, KCP&L and GMO's relationship with its customers is regulated. Further, the customer information and contacts that KCP&L and GMO are selling to Allconnect are developed through that regulated relationship. Finally, moving the revenue and expenses above the line reduces the impression that KCP&L and

> GMO are selling their customer's information to increase their unregulated profits.

There are no expenses or revenues related to Allconnect in KCPL's test year ending December 31, 2015 because the Allconnect expenses and revenues were treated "below the line" in that time period. Therefore, Staff has included a full year of KCPL's allocated share of Allconnect revenues and expenses "above the line" through June 30, 2016. These adjustments are included in Staff's Accounting Schedule 10, adjustments Rev-27.1 and E-198.8.

Related to the revenues and expenses, there is a small amount of plant in service and associated depreciation reserve used in Allconnect activities. Staff has included this plant in service and depreciation reserve in Accounting Schedule 3 – Plant In Service, adjustment P-5.1, and Schedule 6 – Depreciation Reserve, adjustment R-5.1.

Staff Expert/Witness: Keith Majors

26. <u>Common Use Plant Billings</u>

Common use plant is plant on the books of KCPL that can be used by affiliates of KCPL. Common use plant billings are the monthly billings to affiliated entities of KCPL for the entities' use of KCPL's plant. KCPL charges its affiliates for the use of these assets. Included in the charge for common use plant is the impact of any capital additions amount KCPL has expended. An adjustment is necessary to annualize the amount of common use billings. This adjustment is negative, which is a reduction to the cost of service.

Staff's adjustments are identified on Schedule 10 of Staff's KCPL Accounting Schedules, Adjustment E-204.2.

Staff Expert/Witness: Keith Majors

27. <u>Transource Adjustments</u>

KCPL has included in its direct revenue requirement filing two adjustments related to the *Stipulation and Agreement* reached by the parties and included in the Commission's *Report and Order* in File No. EA-2013-0098 ("Transource Missouri Case"). The adjustments include adjustments for the difference between Transource Missouri's FERC revenue requirement and KCPL's FERC revenue requirement and an adjustment to return costs booked in the test year of File No. ER-2012-0174 to KCPL customers.

The first adjustment addresses Transource Missouri's FERC authorized rate incentives. On June 6, 2013, the Signatories in File No. EA-2013-0098, filed a Joint Proposed Order Approving Unanimous Stipulation and Agreement and a Joint Memorandum in Support of the Stipulation. On July 19, 2013 the Signatories filed a Second Joint Proposed Order and Joint Proposed Consent Order Approving Unanimous Stipulation and Agreement and Joint Suggestions of the Signatories in Support of an Order by the Commission Approving the Unanimous Stipulation and Agreement. On August 7, 2013, the Commission issued a *Report and Order* in Case No. EA-2013-0098. In the *Report and Order*, on page 17, in Ordered sections 1 through 4, and in the initial paragraph on page 27 of the attached Appendix 4 "Consent Order" (Second Joint Proposed Order and Joint Proposed Consent Order Approving Unanimous Stipulation and Agreement filed July 19, 2013, by the Signatories), the Commission stated that the disposition of (1) Transource Missouri's application for a certificate of convenience and necessity and (2) KCPL and GMO's application for the transfer of certain transmission property was approved/granted. The Commission also set out at pages 27-28 in Appendix 4 the following from Paragraph 23 of the Joint Proposed Order Approving Unanimous Stipulation and Agreement filed by the Signatories June 6, 2013, in File No. EA-2013-0098:

> A. Rate Treatment – Affiliate Owned Transmission
>
> 1. With respect to transmission facilities located in KCP&L certificated territory that are constructed by Transource Missouri that are part of the Iatan-Nashua and Sibley-Nebraska City Projects, KCP&L agrees that for ratemaking purposes in Missouri the costs allocated to KCP&L by SPP will be adjusted by an amount equal to the difference between: (a) the SPP load ratio share of the annual revenue requirement for such facilities that would have resulted if KCP&L's authorized ROE and capital structure had been applied and there had been no Construction Work in Progress ("CWIP") (if applicable) or other FERC Transmission Rate Incentives, including but not limited to Abandoned Plant Recovery, recovery on a current basis instead of capitalizing pre-commercial operations expenses and accelerated depreciation, applied to such facilities; and (b) the SPP load ratio share of the annual FERC-authorized revenue requirement for such facilities. KCPL&L will make this adjustment in all rate cases so long as these transmission facilities are in service.

The Transource Missouri Annual Transmission Revenue Requirement ("ATTR") reflects costs, such as CWIP, which by itself is not allowed to be recovered in retail rates in Missouri, pursuant to Proposition 1, Section 393.135. In addition, Transource Missouri's FERC authorized return on equity is 50 to 100 basis points higher than KCPL's Missouri authorized return on equity including an additional 50 basis point incentive for belonging to a Regional Transmission Organization ("RTO").

For purposes of this case, KCPL performed an analysis to determine the differences between FERC and KCPL ratemaking for the projects at issue in File No. EA-2013-0098 in order to comply with the Commission's *Report and Order* language quoted above. Staff reviewed KCPL's proposed adjustment and recommends it be revised in various respects to make it consistent with the Commission's *Report and Order* in File No. EA-2013-0098.

Staff's only recommended change is to the assumed cost of long term debt. Differences in the assumed cost of debt do not result from FERC Transmission Rate Incentives, and therefore should not be included in the difference calculation. KCPL has addressed some of Staff's recommendations in File No. ER-2016-0156 concerning this adjustment. These differences were as follows:

- Depreciation rates – depreciation rate differences between the Missouri and FERC jurisdictions do not result from FERC Transmission Rate Incentives, and therefore should not be included in the difference calculation. KCPL has included no difference in depreciation rates for this adjustment in this case.
- State income tax rates – differences in assumed state income tax rates do not result from FERC Transmission Rate Incentives, and therefore should not be included in the difference calculation. KCPL has included no difference in state income tax rates for this adjustment in this case.
- Allowance for Funds Used During Construction ("AFUDC") – this amount, representing the capitalized financing cost for the projects, was adjusted to reflect KCPL and GMO's actual AFUDC rates over time, adjusted for the additional CWIP balance. KCPL has included the actual AFUDC rates and amounts for this adjustment in this case.

Therefore, Staff's adjustment reflects only the differences related to FERC authorized incentives for the difference of costs allocated to KCPL by SPP. This adjustment is included on Schedule 10 of Staff's KCPL Consolidated Accounting Schedules, Adjustment E-129.2.

The second adjustment reflects costs that should have been charged to Transource Missouri but were retained on the regulated books of KCPL for the test year period in File No. ER-2012-0174, 12 months ending September 2011. In File No. ER-2014-0370, KCPL established a regulatory liability in the amount of $136,880 to be amortized over three (3) years.

Staff's adjustment for the annual amortization of these costs is identified on Schedule 9 of Staff's KCPL Consolidated Accounting Schedules, Adjustments E-199.2 and E-206.2.

Staff Expert/Witness: Keith Majors

VIII. Depreciation

A. Staff's Review of KCPL's Submitted Depreciation Study Update

Staff continues to review KCPL's depreciation study, sponsored by its witness John J. Spanos of the consulting firm Gannett Fleming. As described in Mr. Spanos' submitted direct testimony, this is an update of the study performed for Case No. ER-2014-0370.

KCPL requests the addition of a depreciation rate for electric vehicle (EV) charging stations and the removal from the schedule of accounts related to Montrose Unit 1, which has been retired. It appears to Staff that all other updates to the study result from KCPL's request to include terminal net salvage in the calculation of depreciation rates for steam, combustion turbine, and wind production accounts. The rates ordered on by the Commission in the last KCPL rate case, Case No. ER-2014-0370, included only interim net salvage in the calculation of depreciation rates for these accounts.

Staff also recommends adding depreciation rates for the Greenwood Solar Facility. Staff recommends rates for the Greenwood Solar Facility plant included in this case to be the same that were ordered by the Commission in GMO's rate case, Case No. ER-2016-0156.

B. New Account - Electric Vehicle Charging Stations

KCPL requested, through Company witness Mr. Spanos' direct testimony, new plant account 371.1 for Electric Vehicle Charging Stations. Mr. Spanos requested a depreciation rate of 10.0%, based on a 10-S2.5 survivor curve and 0% net salvage, stating that the above proposed are parameters commonly utilized by others that have installed similar EV charging stations.

Staff recommends the removal of plant costs and depreciation reserves, related to EV charging stations, from the cost of service. Please see testimony related to EV charging stations and the Clean Charge Network sponsored by Staff witnesses Keith Majors and Byron M. Murray. Given this, Staff is not recommending depreciation rates for this new requested account.

Depreciation Staff continues to review information and data related to the average service life of EV charging stations, along with potential changes due to industry trends. Currently, Depreciation Staff has no reason to dispute KCPL's requested depreciation rate.

C. Projected Production Unit Retirement Dates

The projected retirement dates for production plants relied on for depreciation purposes by KCPL were used by Staff during the last KCPL rate case, Case No. ER-2014-0370, and have not changed for this rate case. Staff recognizes that any actual future retirement date of a production unit is in no way defined by or a function of an estimated date used to compute a depreciation rate for this rate case.

D. Montrose Unit 1 Retirement

Montrose Generating Station Unit 1 ceased coal-fired energy production on or before April 16, 2016. KCPL direct testimonies and plant and reserve balances assert that the unit has been retired from the Company's books.

During a September 28, 2016 plant tour, Staff observed that Unit 1 had indeed ceased coal-fired generation, and was at the time experiencing demolition activities required to meet environmental regulations, safety standards, and/or mandated decommissioning schedules.

Staff's recommended depreciation schedule reflects the retirement of Montrose Unit 1, and as such the unit does not have any assigned depreciation rates for the applicable steam plant accounts.

E. Greenwood Solar Facility

As described in the testimony of Staff witness Karen Lyons related to the Greenwood solar facility, Staff recommends the allocation of a portion the plant in service for this facility to KCPL. The commission ordered depreciation rates for this facility in GMO's most recent rate case, Case No. ER-2016-0156. Staff recommends the application of these depreciation rates for the portion of the Greenwood plant allocated to KCPL.

F. Staff's Recommended Depreciation Rates

Staff recommends the Commission order KCPL to use the depreciation rates that were ordered in Case No. ER-2014-0370, changing them only to address the retirement of Montrose

Unit 1 and add rates for the Greenwood Solar Facility as discussed above. These rates are shown in Appendix 3, Schedule KBP-1 for all of KCPL's plant accounts. Schedule KBP-1 shows, in addition to Staff's recommended depreciation rates for each plant account: (1) retirement date for depreciation purposes, (2) the expected remaining life as of December 31, 2013, (3) the net salvage rate, (4) statistically-determined retirement rate survivor curve, and (5) the resultant composite depreciation rate. For the accounts related to the Greenwood Solar Facility, only the depreciation rates are shown.

G. Staff's Depreciation Summary

The table below shows the resultant estimated annual depreciation accruals (expense) between KCPL's currently ordered depreciation rates, which Staff recommends with the modifications discussed, and KCPL's requested depreciation rates. Staff used Missouri jurisdictional plant-in-service balances as of June 30, 2016, to derive these depreciation expense comparisons.

Annual Depreciation Expense Comparison (Estimated), June 30, 2016

Currently Ordered / Staff Recommendation	KCPL Requested
$118.9 million	$129.5 million

The method of net salvage computation for steam, combustion turbine, and wind production plant is the main difference between the cases shown. The difference in the net salvage can be explained as follows:

1. Currently ordered KCPL depreciation rates, which Staff recommends, will incur only interim net salvage for the complete account balance;
2. KCPL's proposal includes interim and terminal net salvage for steam, combustion turbine, and wind production plant without limiting the portion of the account balance accruing interim net salvage.

In addition, deprecation expenses related to the Staff recommendation include Greenwood solar facility, which is not included in the estimated KCPL requested depreciation expense. Neither estimates of depreciation expense includes those related to EV charging stations, though KCPL requested the assignment of a depreciation rate for these facilities.

Staff's recommended depreciation rates are shown in Appendix 3, Schedule KBP-d1.

Staff Expert/Witness: Keenan B. Patterson

IX. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by Staff, generally consistent with the methodology used in KCPL's last rate case, Case No. ER-2014-0370. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from the timing required by the Internal Revenue Service ("IRS") in determining taxable income.

Current income tax reflects timing differences consistent with the timing required by the tax regulations. The tax timing differences used in calculating taxable income for computing current income tax for KCPL are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

50% Meals and Entertainment Disallowance

Book Nuclear Fuel Amortization

Book Amortization Expense

Subtractions from Operating Income:

Interest Expense - Weighted Cost of Debt multiplied by Net Rate Base

IRS Accelerated Tax Depreciation

IRS Nuclear Fuel Amortization

IRS Tax Return Plant Amortization

Employee 401k ESOP Deduction

Subtractions - Federal Income Tax Credit:

Wind Production Tax Credit

Research and Development Tax Credit

Fuels Tax Credit

Staff Expert/Witness: Keith Majors

B. Kansas City Earnings Tax

Additionally, Staff normalized the Kansas City, Missouri earnings tax in this rate case. Staff included no amount for earnings taxes, as KCPL is projected to pay no earnings taxes as a result of the extension of bonus deprecation and its impact on taxable income. The amount booked in the test year has been removed in Staff Accounting Schedule 10 – Income Statement in adjustment E-262.1.

Staff Expert/Witness: Keith Majors

C. Deferred Income Tax Expense

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax as the result of the Internal Revenue Code ("IRC"), the timing difference is given "flow-through" treatment. When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of normalizing tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing differences related to accelerated tax depreciation. Deferred income tax expense reflects the portion of calculated income taxes that are not "current" as determined by the regulated utility additions and subtractions to net income and income tax credits. These income taxes will be paid at some point in the future, and in the interim represent a cost-free source of capital.

Staff Expert/Witness: Keith Majors

D. Accumulated Deferred Income Taxes ("ADIT") - Plant Related

KCPL's deferred income tax reserve represents, in effect, a prepayment of income taxes by KCPL's customers and a cost-free source of capital. Because KCPL is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as book-tax timing difference, and creates a deferral, or future liability of income taxes, to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to KCPL.

Therefore, KCPL's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the company. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base. In addition to accelerated depreciation, Staff has also included deferred taxes specifically associated with the rate base inclusion of the pension liability.

The rate base impact of ADIT is included in Schedule 2 – Rate Base in Staff's Accounting Schedules.

Prior to the 1986 Tax Reform Act, flow-through treatment (current year deduction) was used for Missouri utilities unless the utility could demonstrate the need for additional cash flow to meet interest coverage ratios. It is Staff's understanding that KCPL received normalization treatment in rate cases prior to 1986 based upon a need for additional cash flow during significant construction activity related to new generation facilities.

Timing differences which were reflected as a tax deduction in the current year, for current income tax to the IRS, were deferred (normalized) for ratemaking purposes. The tax deduction is reflected in rates by amortizing the deferred tax balance over the depreciable life of the property. Staff's income tax calculation for KCPL, in this current case, reflects the amortization of prior timing differences which were normalized in prior rate cases. Account Schedule 11 reflects an annual amortization of deferred taxes resulting from normalization treatment in prior cases.

The 1986 Tax Reform Act reduced the federal tax rate for corporations from 46% to 34%. As a result all deferred taxes, previously reflected in rates, based upon an assumed 46% tax rate, were overstated. The IRS allowed a regulated utility to flow back (amortize) to ratepayers the excess deferred taxes over the approximate depreciable book life of the property. Staff's income tax calculation for KCPL in this case reflects an amortization of excess deferred taxes resulting from the reduction in the federal tax rate in 1986. This adjustment reflects an annual amortization of the excess deferred taxes resulting from the reduction in the federal tax rate and is located in Accounting Schedule 11.

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property. This adjustment reflects an annual amortization of the deferred investment tax credit and is located in Accounting Schedule 11.

Staff Expert/Witness: Keith Majors

E. ADIT on Construction Work In Progress ("CWIP")

KCPL records ADIT that is associated with the CWIP reflected on its books and records. This ADIT represents a free source of capital funds available for use by the utility before the construction project is completed and included in plant-in-service. CWIP is excluded from the rate base on which KCPL earns a return in the ratemaking process. Although CWIP is not included in rate base, KCPL is allowed to earn an Allowance for Funds Used During Construction ("AFUDC") deferred return before the property under construction is added to rate base. AFUDC is accrued during the construction of the asset and included in rate base when the plant is placed into service. The amount of AFUDC is included in depreciation and rate base over the life of the plant. For the calculation of AFUDC, there is no consideration for ADIT as a reduction to the base on which it is calculated; the AFUDC is calculated on the "gross" amount, with no consideration of ADIT.

Utilities have argued that it is inappropriate to reduce rate base for ADIT associated with CWIP balances, when the CWIP amounts are not included in rate base. However, the Commission has found to the contrary recently. Reducing rate base by the amount of ADIT on CWIP was an issue decided by the Commission in a past Ameren Missouri general rate case, Case No. ER-2012-0166. On page 30 of its *Report and Order* in that case, the Commission stated why this treatment is appropriate:

> In other words, failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially allowing the company to earn AFUDC and a return on capital supplied by ratepayers…
>
> …As fully explained in the findings of fact, Ameren Missouri must include CWIP-related ADIT balances as an offset to rate base to avoid overstating AFUDC and future rate base, to the detriment of both current and future ratepayers.

The Commission recently decided this issue in the 2014 Rate Case on page 79 of its *Report and Order* in that case:

> KCPL asserts that its situation is different than that of the utility at issue in File No. ER-2012-0166 because KCPL has a net operating loss and, as a consequence, KCPL has more deductions than it has revenues during the applicable period, so it has not and will not receive a cash tax benefit. However, KCPL ratepayers provide fully-normalized income taxes in cost of service regardless of whether KCPL pays those taxes concurrently to the IRS. Even if KCPL is not realizing all the benefits of accelerated depreciation due to a net operating loss position, it does not invalidate the fact that ratepayers are providing several million dollars in cash income taxes. The Commission concludes that the amount of ADIT related to CWIP should be an additional reduction to KCPL's rate base.

Therefore, Staff recommends the amount of ADIT on CWIP as of June 30, 2016, be used as an additional reduction to KCPL's rate base, similar to other amounts of ADIT.

The amount of ADIT on CWIP is listed as a reduction to rate base on Schedule 2 – Rate Base, in Staff's Accounting Schedules.

Staff Expert/Witness: Keith Majors

X. Jurisdictional Allocations

The Commission sets cost-of-service based rates for a utility's Missouri retail customers; however, not all of the costs a utility incurs are necessarily associated with its provision of service to its Missouri retail customers. KCPL has both retail and wholesale customers in both Missouri and Kansas. Wholesale sales, under the jurisdiction of the FERC, retail sales in Missouri and retail sales in Kansas are described as sales in three separate "jurisdictions." Some costs to serve a particular jurisdiction may be directly assignable to that jurisdiction; however, some other costs may not. Costs that are not directly assignable to a particular jurisdiction are allocated among the various applicable jurisdictions. Costs that vary with energy consumption, i.e., "variable costs"- are denoted as "energy-related". Costs that do not vary with energy consumption, i.e., "fixed-costs" are denoted as "demand-related." Different allocation factors are developed and utilized for each.

Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are typically allocated on the basis of demand.

Variable costs, such as fuel and purchased power, are more appropriately allocated on the basis of energy consumption. In this case, Staff calculated jurisdictional factors for demand and energy to allocate KCPL's demand-related (fixed) costs and energy-related (variable) costs between three applicable jurisdictions: Missouri retail jurisdiction, Kansas retail jurisdiction and the wholesale jurisdiction. The particular jurisdictional allocation factor applied is dependent upon the type of cost that is being allocated.

Staff Expert/Witness: Alan J. Bax

A. Methodology

1. <u>Demand Allocation Factor</u>

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

Staff is utilizing a Four Coincident Peak (4 CP) methodology – based on the monthly seasonal coincident peaks of the four summer months in calendar year 2015, to determine demand allocation factors for KCPL. The 4 CP method is appropriate for a utility, such as KCPL, that experiences dominant seasonal demands in the four summer months (June through September) relative to the demands in the other eight months of a year. A utility that experiences a needle peak in a particular month may consider utilizing a 1 CP method. Comparatively, a utility that experiences similar hourly peaks in both winter and summer months might employ the 12 CP method. The monthly demands reported for the calendar months included in the test year and update period for the current case are consistent with the monthly demands in the reporting periods associated with the last few rate cases involving KCPL.

Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify KCPL's peak hourly load in each month for the four – month period June 2015 through September 2015 and sum these hourly peak loads.

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

c. Divide b. by a. above.

The result is the allocation factor for each jurisdiction:

Missouri Retail Jurisdiction:	0.5274
Kansas Retail Jurisdiction:	0.4708
Wholesale Jurisdiction:	0.0018
Total:	1.0000

2. <u>Energy Allocation Factor</u>

Variable expenses, such as fuel and purchase power, are allocated to the jurisdictions based on energy consumption. The energy allocation factor for an individual jurisdiction is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction to the utility's total system normalized kWh. In this case, the energy allocation factor for an individual jurisdiction (Missouri Retail, Kansas Retail or Wholesale Jurisdictions) is the ratio of the normalized annual kilowatt-hour (kWh) usage in the particular jurisdiction, during the 12-month period of calendar year 2015, the ordered test year in this case, to KCPL's total system normalized kWh. Staff applied adjustments to these kWhs to account for losses, anticipated growth and certain annualizations. Staff witness Seoung Joun Won, provided the weather adjustment. Staff witnesses Matthew R. Young and Michael J. Stahlman provided the adjustments for customer growth and certain annualizations respectively.

Staff has calculated the following energy allocation factors for the aforementioned jurisdictions based on kWh usage data in calendar year 2015.

Missouri Retail Jurisdiction:	0.5607
Kansas Retail Jurisdiction:	0.4377
Wholesale Jurisdiction:	0.0017
Total:	1.0000

These jurisdictional demand and energy allocation factors were provided to Staff witness Cary G. Featherstone to allocate related costs to the Missouri retail jurisdiction.

Staff Expert/Witness: Alan J. Bax

B. Application

As stated above, KCPL operates within two state jurisdictions, Missouri and Kansas, and in the wholesale jurisdiction regulated by the FERC. Therefore, it is necessary to identify, then allocate and/or assign, KCPL's specific investments and costs among these three jurisdictions (Missouri Retail, Kansas Retail, and Wholesale). To identify KCPL's revenue requirement, Staff must develop KCPL's cost of service for its Missouri retail jurisdiction. To do that, KCPL's plant investments and costs in its income statement must be appropriately assigned or allocated to the Missouri retail jurisdiction.

To develop KCPL's cost of service for its Missouri retail jurisdiction, Staff began with KCPL's records kept in accordance with FERC accounting requirements per Commission rule. Where these records reflected costs or investments that KCPL incurred solely to serve the Missouri retail jurisdiction, Staff directly assigned those costs or investments to KCPL's Missouri jurisdictional cost of service. However, when it was not appropriate to directly assign costs or investments, Staff allocated those costs using either a demand allocation factor or an energy allocation factor, depending upon whether the investment or cost is more related to demand or energy.

KCPL uses its generation and transmission facilities to produce and transport electricity to its Missouri retail customers, Kansas retail customers, and wholesale customers (FERC jurisdiction). Because these facilities are demand-related, Staff allocated KCPL's costs and investments in these facilities, as well as the related depreciation reserve accounts, to the two state and one federal jurisdiction using the demand allocator. Since KCPL is a four summer month peaking utility, Staff used the 4 coincident peak ("4 CP") method to develop the Missouri retail jurisdiction, Kansas retail jurisdiction, and wholesale jurisdiction demand allocators. Staff has consistently used the 4 CP method to develop the KCPL demand allocators since KCPL's 1985 Wolf Creek rate case, including each of the four KCPL Regulatory Plan rate cases filed with the Commission and the 2012 and 2014 rate cases.[95]

The Commission has approved the use of the 4 CP method to allocate joint investment costs and expenses since the 1985 Wolf Creek rate case. The Commission decided the use of the 4 CP method was proper again in 2006 KCPL rate case.[96]

Distribution Plant Investment

In its records kept in accordance with FERC accounting requirements, KCPL separately accounts for its investment in distribution plant located in Kansas and Missouri. Plant identified in this way is referred to as site specific or *situs* plant. Staff used KCPL's actual distribution plant investment in both Missouri and Kansas at June 30, 2016, to develop site specific allocation factors to allocate the total company distribution plant and reserve amounts to quantify only the distribution plant and reserve amounts specific to KCPL's Missouri retail jurisdiction. This is consistent with how KCPL treated distribution plant in its case.

General Plant Allocation

Staff created the Missouri retail jurisdictional allocation factor for general plant investment, and related costs, based on a composite of its demand allocation factor and site specific allocation factor. Staff applied the demand allocation factor used to quantify the Missouri retail jurisdictional share of KCPL's production and transmission costs and the site specific allocation factor used to allocate an appropriate part of KCPL's total company distribution plant and reserve amounts to KCPL's Missouri retail jurisdiction. Staff used the resulting production plant and depreciation reserve amounts and distribution plant costs allocated to KCPL's Missouri retail jurisdiction to form the basis for allocating KCPL's general plant to its Missouri retail jurisdiction. Thus, Staff's Missouri retail jurisdiction allocation factor for KCPL's general plant is based on a composite of the Missouri retail jurisdiction allocation factors Staff developed for KCPL's production, transmission and distribution plant costs. Staff

[95] The four rate cases filed under the Experimental Regulatory Plan authorized by the Commission in Case No. EO-2005-0329 are Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089, and ER-2010-0355 and the last KCPL two rate cases, ER-2012-0174 and ER-2014-0370.

[96] *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of its Regulatory Plan,* Case No. ER-2006-0314, (*Report and Order,* filed December 21, 2006) page 74.

used this composite general plant allocation factor to allocate to KCPL's Missouri retail jurisdiction what are described in KCPL's income statement (Staff Accounting Schedule 9) as "general" costs.

Allocations of Expenses

Using the principle that expenses (costs) should follow plant investment, Staff used the same jurisdictional allocation factors it developed to allocate investment to allocate expenses related to that investment. The FERC expense accounts found in KCPL's income statement (reproduced as Schedule 9 in Staff's Accounting Schedules) include amounts for costs broadly described as production, transmission, distribution, general, and administrative and general ("A&G"). Using the expense accounts found in KCPL's income statement, this principle that expenses should follow plant investment is appropriate because KPCL incurs production (generation) plant expenses to maintain and operate its the generation facilities, making it proper to use the same jurisdictional allocator to allocate production plant expenses that is used to allocate its investment costs in generating facilities. Similarly, KCPL incurs transmission expenses to maintain and operate its transmission facilities, making it appropriate to use the same jurisdictional allocator to allocate transmission expenses that is used to allocate KCPL's investment costs in transmission facilities.

Staff allocated KPCL's production and transmission costs taken from KCPL's income statement to KCPL's Missouri retail jurisdiction with the same demand allocator Staff developed and used to allocate KCPL's investment in generating and transmission facilities to KCPL's Missouri retail jurisdiction.

Other Costs Allocations

Staff also used a variety of jurisdictional allocation factors to allocate the appropriate part of KCPL's administrative and general costs found in KCPL's income statement (Staff Accounting Schedule 9), to KCPL's Missouri retail jurisdiction. Staff relied on KCPL for these allocation factors. Some of these allocation factors are based on the number of KCPL customers in each jurisdiction. Some are based on the number of KCPL employees working in each jurisdiction. Each specific account had a specific allocation factor that Staff used to allocate the appropriate cost to KCPL's Missouri retail jurisdiction.

Energy and Demand Allocations

Staff used the energy allocation factor to allocate costs to the Missouri retail jurisdiction that are considered to vary directly with electricity usage. For example, in response to increased demand for electricity in a particular hour, KCPL must either buy or generate more electricity, causing one or more of its fuel and purchased power costs to increase. In contrast, costs such as fixed capacity or demand charges on a purchased power contract are constant, regardless of the demand for electricity in a given non-peak hour and, therefore, are allocated using the demand allocator.

The demand portion of capacity agreements are assigned or allocated to the jurisdictions using the demand allocator. However, energy sold or purchased using that capacity is a variable cost and is allocated to the jurisdictions with energy allocation factors. The rationale for the demand portion of a capacity purchase or sale agreement is to recover the costs of the facilities that underlie these transactions. For example, if KCPL sells capacity, KCPL makes a commitment to have generating capacity in place that is dedicated to meeting the load requirements of the customer to whom it is selling the capacity. The demand portion of a capacity sale can be thought of as the recovery of the costs of generating assets used to provide electricity to the buyer of power. Similar to when it sells capacity, when KCPL purchases capacity to assure it can meet its system load requirements with energy, it will pay a demand charge (payment) to the seller.

On March 2014, SPP implemented an integrated market to dispatch generation to meet the system load requirements for all its members. However, for purposes of presenting this rate case, Staff has developed KCPL's revenue requirement on the assumption that the Missouri-allocated portions of all of KCPL's generation facilities are primarily used to produce electricity for KCPL's retail customers. Accordingly, Staff's assumption is that KCPL meets its native load with the same generating plant and transmission plant that it uses to generate and transport electricity to make off-system sales—sales to firm and non-firm customers in the bulk power markets (off-system sales). Staff uses the energy allocation factor to allocate energy (variable) costs of fuel and purchased power that are assumed to be incurred to meet system load requirements of KCPL's native load customers. Staff also used the same energy factor used to allocate the variable costs incurred to meet retail load requirements for Missouri retail customers to allocate KCPL's revenues and energy costs that are assumed to be incurred to make off-system sales to its Missouri retail jurisdiction. Since the non-firm, off-system sales market is made up of short-term sales, Staff assumes that KCPL does not reserve dedicated generating capacity for these sales. Traditionally, non-firm off-system sales have been allocated using the energy allocation factors since the costs of making these sales are variable in nature, primarily being the cost of the fuel used to generate the electricity sold. As more megawatts are sold, more fuel is consumed or power purchased and, therefore, the higher the fuel cost or the purchased power cost. These costs vary directly with the megawatt hours sold or purchased and, thus, using the energy allocation factors is proper. Staff has used energy allocation factors to allocate off-system sales to KCPL's Missouri retail jurisdiction in each of KCPL's last four rate cases during its Regulatory Plan and in the 2012 and 2014 KCPL rate cases. Historically, Staff has consistently used energy allocation factors to allocate off-system sales revenues to the Missouri retail jurisdiction of The Empire District Electric Company and for setting retail rates in what was GMO's MPS rate district for many rate cases, dating back to at least the 1990s. Pre-consolidation, GMO's L&P rate district was a Missouri jurisdictional only utility, so has no jurisdictional allocations.

Staff Expert/Witness: Cary G. Featherstone

XI. Fuel Adjustment Clause ("FAC")

A. FAC - Policy

In summary, Staff makes the following recommendations regarding KCPL's Fuel Adjustment Clause ("FAC") to the Commission:

1. Continue KCPL's FAC with modifications;
2. Include a new Base Factor and a new percentage of SPP transmission service costs in the FAC tariff sheets calculated from the Net Base Energy Cost[97] that the Commission includes in the revenue requirement upon which it sets KCPL's general rates in this case;
3. Order KCPL to suspend all of its hedging activities (cross hedging and fuel hedging);

[97] Net Base Energy Cost is defined in KCP&L's Original Sheet No. 50.7 as "Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA".

4. Clarify that the only SPP transmission costs that are included in KCPL's FAC are those that KCPL incurs to transmit electric power it did not generate to its own load (true purchased power) and costs to transmit excess electric power it is selling to third parties in locations outside of SPP as off-system sales ("OSS");
5. Order KCPL to continue to provide the additional information as part of its monthly reports[98] as the Commission ordered KCPL to do in the previous Rate Case No. ER-2014-0370, along with the information already required in its monthly reports.

Staff Expert/Witness: David C. Roos

1. History

The Commission first authorized a FAC for KCPL in its *Report and Order* in KCPL's 2015 general electric rate proceeding (Case No. ER-2014-0370), with the original FAC tariff sheets becoming effective September 29, 2015. This general rate case is the first KCPL general rate case after Commission authorization of KCPL's FAC. KCPL is requesting continuance of the FAC in this rate case. The primary features of KCPL's present FAC (tariff sheets numbered 50 through 50.10) include:

- Two 6-month accumulation periods: January through June and July through December;
- Two 12-month recovery periods: October through September and April through March;
- Two FAR filings annually, not later than February 1 and August 1;
- A 95%/5% sharing mechanism;
- FARs for individual service classifications are rounded to the nearest \$0.00001, and charged on each applicable kWh billed;
- True-up of any over- or under-recovery of revenues following each recovery period with true-up amounts being included in determination of FARs for a subsequent recovery period; and,

[98] Monthly reports are required by 4 CSR 240-3.161(5).

- Prudence reviews of the costs subject to the FAC shall occur no less frequently than every eighteen months.

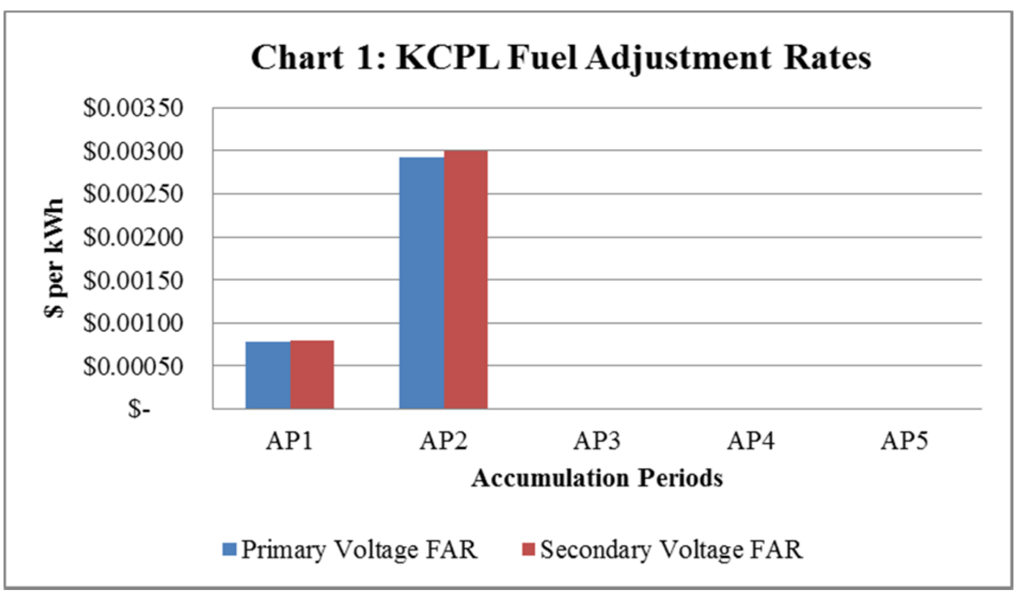
The Base Factor (base energy cost per kWh rate) was originally set in KCPL's 2015 rate case (Case No. ER-2014-0370) to be $0.01186 per kWh. In this case, KCPL is proposing to increase the FAC Base Factor to $0.01987 per kWh.

Staff Expert/Witness: David C. Roos

2. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of KCPL's FAC. Staff also recommends that the Commission reset the Base Factor. Staff will provide its estimate of the Base Factor for the FAC and a discussion on the calculation of the Base Factor when Staff files its Class Cost of Service/Rate Design Report on December 14, 2016. Staff will use the Net Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

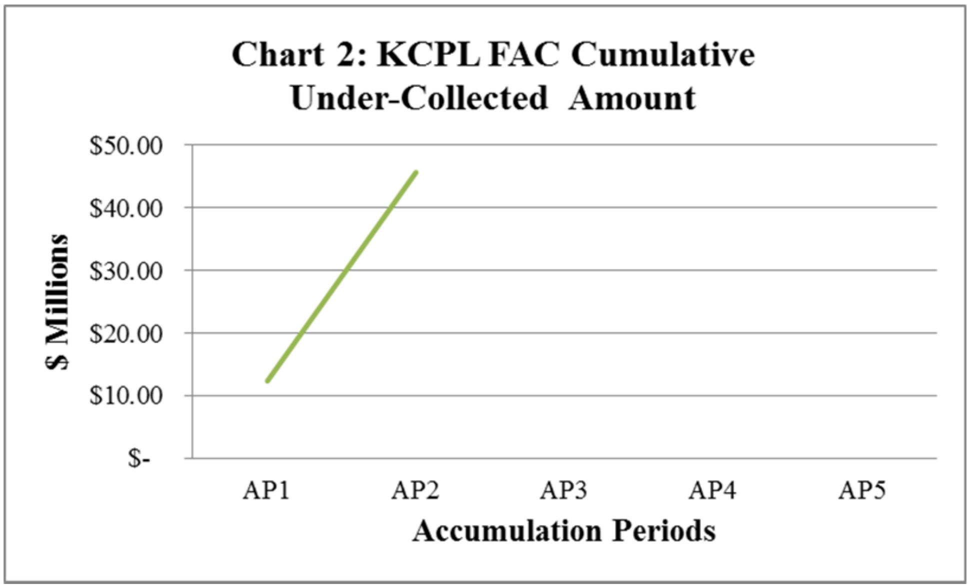
KCPL has filed for and received approval of changes to its FARs for two (2) completed accumulation periods ("AP") (AP1 and AP2). Chart 1 shows the FARs for these accumulation periods.



The time periods of the two accumulation periods are:

AP1: Sep 29, 2015[99] – Dec 2015 AP2: Jan 2016- Jun 2016

Chart 2 shows KCPL's Actual Net Energy Cost have exceeded the Base Factor multiplied by monthly usage billed to KCPL's customers' in both of the completed accumulation periods.



Actual FAC costs include: KCPL's total booked costs as allocated for fuel consumed in the Company's generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs; air quality control system consumables; and net emission allowance costs. Actual FAC costs are off-set by actual revenue from Off-System Sales and actual Renewable Energy Credit Revenues to produce the FAC Actual Net Energy Cost (ANEC). In the two accumulation periods (AP1 and AP2), KCPL under-collected its Actual Net Energy Costs, and 95% of the under-collected amounts were recovered from KCPL's customers during recovery periods RP1 and RP2. The ANEC per kWh was $0.01526/kWh during AP1 and $0.01629/kWh during AP2.

[99] September 29, 2015 is the effective date of rates for Rate Case No. ER-2014-0370.

For the AP1 and AP2, Chart 3 illustrates the percentage of cumulative under-collected amount which is equal to 100*(ANEC-B)/ANEC where “B” is the Net Base Energy Cost for KCPL.[100]

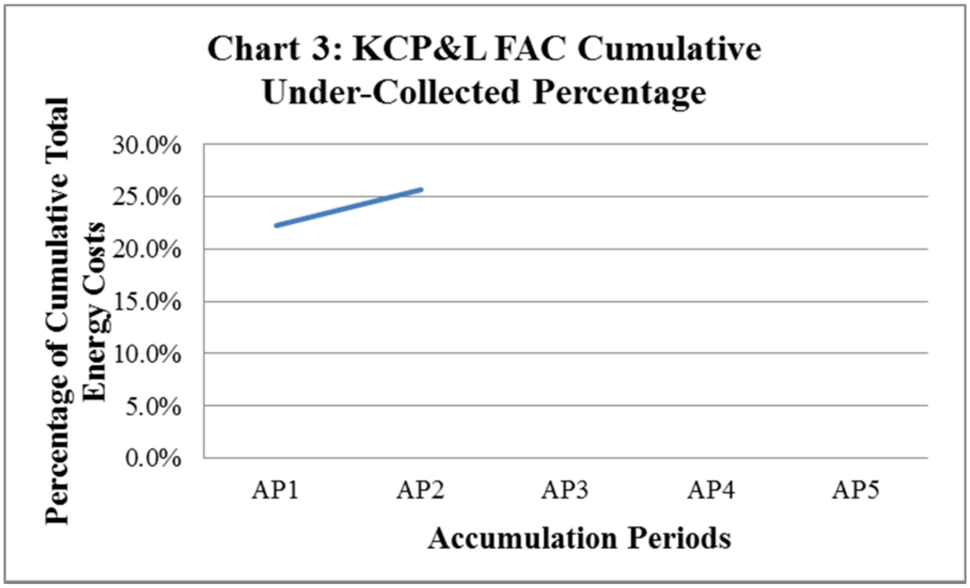


Chart 1 illustrates the variability of the FARs as a result of variations in each accumulation period’s billed Net Base Energy Cost and Actual Net Energy Cost. From Charts 2 and 3, Staff observes that the FAC cumulative under-collected amount over 12 months is approximately $45.7 million or about 26% percent of total Actual Net Energy Cost, which totaled $178 million during AP1 and AP2.

Staff recommends continuation of KCPL’s FAC with modifications. As shown in the previous charts and discussion, KCPL’s Actual Net Energy Costs continue to be relatively large,[101] volatile, and beyond the control of the Company.

Staff Expert/Witness: David C. Roos

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[100] B is defined as Net Base Energy Cost is defined in KCPL’s Original Sheet No. 50.7 as “Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA”.

[101] KCPL’s proposed Base Energy Cost for this case represents 37% of KCPL’s total cost to be recovered in rates.

B. Hedging Activities

1. History

KCPL engaged in hedging activities in an effort to reduce the risk of operating generation plants fueled by natural gas (fuel hedging) and price risk associated with electrical energy purchases (cross hedging). KCPL attempted to manage these risks through a process of purchasing New York Mercantile Exchange (NYMEX) natural gas futures contracts.[102] KCPL's hedging activities are a component of its FAC.[103] KCPL's fuel hedging can be described as a traditional natural gas price hedge plan while its cross hedging program is a non-traditional natural gas price hedge plan. All of the IOUs in Missouri hedge for the natural gas fuel that is burned in its generators; however, KCPL and GMO have also used a hedging strategy to reduce price risk of electrical energy purchases.

In the Non-Unanimous Stipulation and Agreement, filed on September 20, 2016, in Case No. ER-2016-0156, GMO agreed to:

> … suspend all of its hedging activities associated with natural gas (cross-hedging related to purchased power and natural gas fuel hedging). Upon approval of this Stipulation, GMO will expeditiously proceed to unwind all of its hedges associated with natural gas. Any gains or losses from the unwinding of the natural gas hedges will be flowed through GMO's Fuel Adjustment Clause ("FAC") without disallowance. The Signatories agree GMO may resume its natural gas fuel hedging activities (but not use natural gas derivatives to cross-hedge purchased power) should the market place and/or other factors change such that resuming natural gas fuel hedging activities would be warranted. GMO agrees to notify the Commission Staff and the Office of the Public Counsel ("Public Counsel") if GMO decides to resume its natural gas fuel hedging activities. In the event GMO resumes natural gas fuel hedging activities, GMO will record all hedging gains to FERC Account 254, Regulatory Liability and hedging losses to FERC Account 182.3 Other Regulatory Assets or FERC Account 186, Deferred Debits. This deferral is agreed upon for purposes solely described in this paragraph and does not apply to or set precedent for any other case or expense. All parties are free to argue for the ratemaking treatment of any amounts deferred under this language and the ongoing treatment of hedging costs.

[102] Natural gas future contracts are marketed through NYMEX (a division of the CME Group) and are financial transactions and no physical natural gas commodity will change hands.

[103] KCPL FUEL ADJUSTMENT CLAUSE – Rider FAC Original Sheet No. 50.2.

Consistent with the Non-Unanimous Stipulation and Agreement, in Case No. ER-2016-0156, KCPL has also stopped using natural gas derivatives to cross-hedge power transactions, and has stopped hedging natural gas used as fuel as of September 2016.[104]

Staff recommends the Commission order KCPL to suspend all of its hedging activities (cross hedging and natural gas fuel hedging) associated with natural gas, and require KCPL to notify the Commission Staff and the Public Counsel if KCPL decides to resume its natural gas fuel hedging activities. This suspension should be consistent with the Non-Unanimous Stipulation and Agreement, Filed September 20, 2016, in Case No. ER-2016-0156.

Accordingly, Staff recommends accounting schedules for this general rate case reflect \$0.00 in permanent rates and \$0.00 to the FAC base factor for natural gas hedging.

Staff Expert/Witness: David C. Roos

2. <u>Transmission</u>

Staff recommends to the Commission that only SPP transmission costs that KCPL incurs to transmit electric power it did not generate for its own native load and costs to transmit excess electric power it is selling to third parties at locations outside of the SPP be included in KCPL's FAC. This recommendation is consistent with the Commission's *Report and Order* in KCPL's last general rate case (Case No. ER-2014-0370) and represents no change to KCPL's FAC. Beginning on page 34 of the Commission's *Report and Order* in File No. ER-2014-0370, the Commission stated the following:

> The Commission has addressed this issue in recent rate cases. In the Report and Order issued in File No. ER-2014-0258 for Ameren Missouri, the Commission stated:
>
> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view. The drafters of the FAC statute likely did not envision a situation where a utility would consider all its generation purchased power or off system sales. In fact, the policy underlying the FAC statute is clear on its

[104] Based on KCPL's response to Staff Data Request No. 0242.

> face. The statute is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power. At the time the statute was drafted, and even in our more complex present-day system, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified. Therefore, of the three reasons Ameren Missouri incurs transmission costs cited earlier, the costs that should be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power) and 2) costs to transmit excess electric power it is selling to third parties to locations outside of MISO (off-system sales). Any other interpretation would expand the reach of the FAC beyond its intent.

Similarly, in a subsequent rate case for The Empire District Electric Company, (Case No. ER-2016-0023) which is also a member of SPP, the Commission concluded:

> Furthermore, as has been the case since the FAC statute was created, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified. Therefore, the costs Empire incurs related to transmission that are appropriate for the FAC, from a policy perspective and by statute, are: 1) Costs to transmit electric power it did not generate to its own load ("true purchased power"); or 2) Costs to transmit excess electric power it is selling to third parties to locations outside of its RTO ("Off-system sales").
>
> The evidence shows in this case that on a daily basis, KCPL sells all of the power it generates into the SPP market and purchases from SPP 100% of the electricity it sells to its retail customers. However, based on the Commission's analysis in the two cases cited above, it would not be lawful for KCPL to recover all of its SPP transmission fees through the FAC. In addition, while KCPL's transmission costs are increasing, those costs are known, measurable, and not unpredictable, so the costs are not volatile. The Commission concludes that the appropriate transmission costs to be included in the FAC are 1) costs to transmit electric power it did not generate to its own load (true purchased power); and 2) costs to transmit excess electric power it is selling to third parties to locations outside of SPP (off-system sales).

Staff recommends that the Commission continue to exclude Regional Transmission Organization ("RTO") administrative fees and Regulatory Commission Expense from KCPL's FAC. These expenses are administrative in nature and are not related to fuel and purchased power expenses. This is consistent with the Commission's *Report and Order* in KCPL's last general rate case, Case No. ER-2014-0370, and represents no change to KCPL's existing FAC. Beginning on page 36 of the Commission's *Report and Order* in Case No. ER-2014-0370, the Commission stated the following:

> KCPL has requested that SPP Schedule 1-A and 12 fees be included in its FAC. The Commission finds that these fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers. These fees are neither fuel and purchased power expenses nor transportation expenses incurred to deliver fuel or purchased power. The Commission concludes that including such fees would be unlawful under Section 386.266.1, RSMo, and, therefore, Schedule 1-A and 12 fees should not be included in the FAC. These fees are appropriate for recovery in base rates.

Staff Expert/Witness: David C. Roos

C. Revising the Base Factor

Correctly setting the Base Factor in KCPL's FAC tariff sheets is critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism. For the reasons below, Staff recommends the Commission require the Base Factor in KCPL's FAC be set based on the Base Energy Cost that the Commission includes in the revenue requirement on which it sets KCPL's general rates in this case.

Table 1 below shows three scenarios in which the FAC Base Energy Cost used to set the FAC Base Factor are equal to, less than, or greater than the Base Energy Cost in the revenue requirement upon which the Commission sets general rates:

continued on next page

Table 1: Base Energy Cost Case Studies				
		Case 1	Case 2	Case 3
Line	**95%/5% Sharing Mechanism**	Energy Cost in FAC **Equal To** Base Energy Cost in Rev. Req.	Energy Cost in FAC **Less Than** Base Energy Cost in Rev. Req.	Energy Cost in FAC **Greater Than** Base Energy Cost in
a	Revenue Requirement	$ 10,000,000	$ 10,000,000	$ 10,000,000
b	Base Energy Cost in Rev. Req.	$ 4,000,000	$ 4,000,000	$ 4,000,000
c	Base Energy Cost in FAC	$ 4,000,000	$ 3,900,000	$ 4,100,000
	Outcome 1: Actual Energy Cost **Greater Than** Base Energy Cost in Revenue Requirement			
d	Actual Total Energy Cost	$ 4,200,000	$ 4,200,000	$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
e = (d - c) x 0.95	through FAC	$ 190,000	$ 285,000	$ 95,000
f = b + e	Total Billed to Customers	$ 4,190,000	$ 4,285,000	$ 4,095,000
g = f - d	**Kept/(Paid) by Company**	**$ (10,000)**	**$ 85,000**	**$ (105,000)**
	Outcome 2: Actual Energy Cost **Less Than** Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	$ 3,800,000	$ 3,800,000	$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
i = (h - c) x 0.95	through FAC	$ (190,000)	$ (95,000)	$ (285,000)
j = b + i	Total Billed to Customers	$ 3,810,000	$ 3,905,000	$ 3,715,000
k = j - h	**Kept/(Paid) by Company**	**$ 10,000**	**$ 105,000**	**$ (85,000)**

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

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

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

These three cases illustrate the importance of setting the Base Factor in the FAC correctly, i.e., revising the Base Factor to match the Base Energy Cost in the revenue requirement used for setting general rates. Therefore Staff recommends the Base Factor be set to match Base Energy Cost in the Commission ordered revenue requirement, as shown in Case 1, because it does not lead to over- or under-collection, which is preferred, and illustrates how the FAC is intended to work.

Staff Expert/Witness: David C. Roos

D. Additional Reporting Requirements

Due to the accelerated Staff review process necessary with FAC adjustment filings,[105] Staff recommends the Commission again order[106] KCPL to continue to provide the following information as part of its monthly reports:

1. As part of the information KCPL submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include KCPL's calculation of the interest included in the proposed rate;
2. Maintain at KCPL's corporate headquarters or at some other mutually agreed-upon place and make available within a mutually-agreed-upon time for review, a copy of each and every coal, coal transportation, natural gas, fuel oil, and nuclear fuel contract KCPL has that is in or was in effect for the previous four years;
3. Within 30 days of the effective date of each and every coal, coal transportation, natural gas, fuel oil, and nuclear fuel contract KCPL enters into, KCPL provide both notice to the Staff of the contract and opportunity to review the contract at KCPL's corporate headquarters or at some other mutually-agreed-upon place;
4. Provide a copy of each and every KCPL hedging policy that is in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain;

[105] The company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff's recommendation.

[106] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service,* Case No. ER-2014-0370, (*Report and Order*, issued September 2, 2015) pp. 47-48.

5. Within 30 days of any change in a KCPL hedging policy, provide a copy of the changed hedging policy for Staff to retain;
6. Provide a copy of KCPL's internal policy for participating in the SPP's Integrated Market;
7. Maintain at KCPL's corporate headquarters or at some other mutually agreed-upon place and make available within a mutually agreed-upon time for review, a copy of each and every bilateral energy or demand sales/purchase contract;
8. If KCPL revises any internal policy for participating in the SPP, within 30 days of that revision, provide a copy of the revised policy with the revisions identified for Staff to retain; and, the monthly as-burned fuel report supplied by KCPL required by 4 CSR 240-3.190(1)(B) shall explicitly designate fixed and variable components of the average cost per unit burned, including commodity, transportation, emissions, tax, fuel blend, and any additional fixed or variable costs associated with the average cost per unit reported.

Staff Expert/Witness: David C. Roos

E. Fuel Adjustment Clause Heat Rate and Efficiency Testing

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

> (Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG[107], steam turbines and combustion turbines conducted within the previous twenty-four (24) months;

The Commission first authorized KCPL's FAC in Case No. ER-2014-0370. KCPL is requesting that its FAC be continued with modification in this case.

[107] Heat recovery steam generator.

Company witness Burton L. Crawford filed testimony that included several attachments that identify supply-side and demand-side resources expected to meet KCPL's load requirements and which also contain the results of the most recent heat rate/efficiency tests for many of KCPL's generating units.

Each generating unit's fuel type and expected annual MWh dispatch levels for years 2017, 2018, 2019 and 2020 are contained in Schedule BLC-5. [108]

Schedule BLC-6 contains the results of heat rate tests for KCPL's generating units.[109] Additional information necessary to comply with 4 CSR 240-3.161(3)(Q) is provided in KCPL's responses to Staff Data Request No. 0189 and Staff Data Request No. 0309.

Staff's review of Company witness Burton L. Crawford's testimony, KCPL's response to Staff Data Request 0189, and KCPL's response to Staff Data Request No. .0309 confirms that each generating unit meets the previous 24-month heat rate testing requirement of Commission Rule 4 CSR 240-3.161(3)(Q).

Staff Expert/Witness: J Luebbert

XII. Other Miscellaneous Issues

A. Clean Charge Network

1. <u>KCPL Clean Charge Network Schedule CCN ("CCN") Tariff</u>

KCPL and GMO have launched an initiative to install and operate more than 1,000 electric vehicle ("EV") charging stations throughout the Greater Kansas City region within KCPL's Missouri and Kansas territories and GMO service territories ("Clean Charge Network" or "CCN").[110] KCPL submitted a new tariff (Public Electric Vehicle Charging Station Service Schedule CCN) to charge EV owners who fill up/charge their vehicles at the CCN charging stations throughout the KCPL region. The Pilot Program consisted of free electricity for EV owners for the first two years of the program. The two year "free" period will end December 31,

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[108] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2016-0285 (*Direct testimony of Burton L. Crawford,* Schedule BLC-5, Filed July 1, 2016).

[109] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2016-0285 (*Direct testimony of Burton L. Crawford,* Schedule BLC-6, filed July 1, 2016).

[110] *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service*, Case No. ER-2016-0285 (*Direct Testimony of Tim Rush*, filed July 1, 2016) Page 21, Lines 2-5.

2016. The proposed Schedule CCN dictates the allowable energy charges for EV owners and discretionary session charges set by the host site owners, which will be explained further below.

The CCN is designed to address KCPL's service territories (KCPL and GMO) and to service KCPL's mobile customers when they are in KCPL's certificated territory.[111] It is specific to KCPL-owned charging stations available to the public throughout KCPL's Missouri service territory. The proposed tariff does not address charging of EVs at customer single-family residences or at privately owned and operated charging stations like some businesses have provided at their sites specifically for their employees and guests.

The total budgeted capital cost for the (whole) project (Kansas and Missouri) is $16.6 million of which, based upon the service territory deployment plan, approximately $6 million would represent the budgeted investment in KCPL's Missouri jurisdiction as the result of situs-based allocators. In addition to these costs, KCPL anticipates total annual operations and maintenance ("O&M") expense of roughly $250,000 which will be allocated to KCPL's Missouri jurisdiction.[112]

The CCN project involves just over 1,000 charging stations throughout KCPL and GMO's service territories. The actual number of charging stations located in Missouri will be determined, in part, by host interest. KCPL included a cap in Schedule CCN of 400 charging stations[113] with Commission approval required for additional stations under the tariff.[114]

After reviewing all of the information presented at the workshop and provided in the docket; (File No EW-2016-0123, *In the Matter of a Working Case Regarding Electric Vehicle Charging Facilities*), Staff counsel advises that existing Missouri law generally requires the Commission to regulate the operation of EV charging stations and the rates charged for their use. Staff counsel further advises that the proposed session charges violates § 393.130, RSMo, by permitting unregulated third parties to set a portion of rates.

STAFF RECOMMENDATIONS

Staff recommends that the Commission only approve KCPL'S proposed tariff sheets subject to revisions addressing the session charge and on the condition that all revenues,

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[111] *__Id.__* at Page 21, Lines 9-16.
[112] *__Id.__* at Page 28, Lines 1-3.
[113] *__Id.__* (Rush's testimony cites 350 charging stations for KCPL-Mo, while the tariff cites 400 charging stations.)
[114] *__Id.__* at Page 28, Lines 7-11.

expenses and investment associated with the program are recorded below-the-line in order to hold ratepayers harmless. Please see the Audit Sections explanation in the Cost of Service Revenue Requirement Report submitted by Keith Majors. Staff's adjustments are identified on Schedule 10 of Staff's KCPL Accounting Schedules, Adjustment E-154.4, and Schedule 3 – Plant in Service, Adjustment P-290.1, and Schedule 6 – Accumulated Depreciation Reserve, Adjustment R-290.1. The deferred tax adjustment is identified on Staff Accounting Schedule 2 – Rate Base.

Further, consistent with its recommendations in File No. EW-2016-0123, Staff recommends KCPL be required to gather data and report annually to the Commission and interested stakeholders on the impact of electric vehicle charging stations on grid reliability.

To learn from the pilot projects, Staff recommends KCPL gather data and report annually to the Commission and interested stakeholders on the impact of EVs on grid reliability as items such as:

1. EV Load Leveling
    a. Did the load increase overnight due to EV charging?
    b. Did the load level as a direct result of the EV charging network?
    c. Did the EV load allow the utilities to spread out fixed generation cost and recover over a greater amount of electricity sold?
    d. Impact on customer bills due to EV load and the resulting load leveling?
    e. Did the EV network prevent periods of over-generation?
    f. Did the EV network smooth out large load ramps in the morning and evening?
2. The IOUs explore various emerging technologies and their impact on the areas of demand-response, supply-side resourcing and second battery life programs[115].

Staff Expert/Witness: Byron M. Murray

2. <u>Clean Charge Network Expenses and Plant Investment</u>

After the Commission concluded in Case No. ER-2014-0370 that KCPL "failed to meet its burden of proof to demonstrate that the charging stations placed in service in its Missouri service territory as of May 31, 2015, should be included in rate base as a part of the revenue

[115] *In the Matter of a Working Case Regarding Electric Vehicle Charging Facilities*, File No. EW-2016-0123, (*Corrected Staff Report*, filed August 9, 2016). Page 30.

requirement for this case," The Commission established a working docket, File No. EW-2016-0123, and ordered Staff to investigate and report on the legal and policy regulatory issues related to both the installation and operation of electric charging facilities and the associated sale of electricity to electric vehicle owners. Staff filed a report in this working docket on August 5, 2016, and within it, Staff made several recommendations concerning electric vehicle charging stations. On October 20, the Commission closed the working docket.

In this case Staff recommends the removal of the O&M expense, plant in service, and accumulated depreciation reserve related to the Clean Charge Network from KCPL's cost of service. The rationale for Staff's recommendation is explained in the testimony of Byron M. Murray in a separate section of this report.

KCPL's response to Staff Data Request 206 in this Case, No. ER-2016-0285, identified the plant in service and O&M expense related to the Clean Charge Network as of June 2016. Deferred taxes related to this plant-in-service were identified as of December 31, 2015. Staff has estimated the accumulated depreciation reserve and deferred taxes related to the Clean Charge Network as of June 30, 2016. Staff will update these amounts with actual known and measurable changes through the true-up date of December 31, 2016.

Staff's adjustments are identified on Schedule 10 of Staff's KCPL Accounting Schedules, Adjustment E-154.4, and Schedule 3 – Plant in Service, Adjustment P-290.1, and Schedule 6 – Accumulated Depreciation Reserve, Adjustment R-290.1. The deferred tax adjustment is identified on Staff Accounting Schedule 2 – Rate Base.

Staff Expert/Witness: Keith Majors

B. Test Year MEEIA Costs

Since KCPL's MEEIA program costs are recovered outside of base rates, Staff made adjustments E-180.5 and E-184.1 to remove test year MEEIA costs from the cost of service calculation.

Staff Expert/Witness: Matthew R. Young

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

On June 1, 2016, KCPL filed with the Commission revised tariff sheets[116] to allow it to pursue a structured conversion of all roadway lighting (non-decorative, pole mounted, over road lighting) to LED fixtures. On June 2, 2016, KCPL provided to Staff and the Office of Public Counsel, a LED Roadway Lighting Evaluation Summary and Conversion Proposal ("Report") and workpaper to support the tariff sheet filing. Within the Report, KCPL proposed that for its KCPL-Missouri jurisdiction, it be allowed to complete a structured conversion of all roadway lighting (non-decorative, pole mounted, over road lighting) to LED luminaires. KCPL-Missouri proposed to convert an estimated seven thousand five hundred (7,500) lights over an approximate six (6) month period using a combination of four (4) LED luminaire sizes equivalent in lighting efficacy to the current lights. KCPL intends to convert lights in geographic areas during times that will efficiently utilize its crews and minimize travel time. On September 2, 2016, KCPL informed Staff they had completed procuring LED fixtures into their inventory and had been in contact with the cities where the conversion would start.

KCPL states in its Report:

> Company research and research results obtained publically support that LED lighting is a viable option for lighting of public roadways. There has been significant development, improvement, and standardization of the LED technology occurring among the vendors, allowing the Company to identify luminaire options suitable for deployment. Prior to 2016, the rate of change for LED luminaires was too rapid to support definition of a LED lighting standard and incorporating it to Company inventories. Often, before a Request for Proposal could be executed, light designs would become obsolete. Also of note is the price for LED luminaires. While still higher per unit than the more mature HPS alternatives, luminaire prices have declined significantly over the past year to a point where the installations are economically feasible.

KCPL also stated in its Report that, "Although this proposal is limited to roadway lighting and does not address decorative lighting, area lighting, or directional lighting, KCP&L intends to continue to monitor the available options and will propose implementation of LED under these applications as it becomes practical to do so."

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[116] On July 1, 2016, the revised tariff sheets as filed on June 1, 2016, went into effect.

Through recent email correspondence, KCPL has agreed to continue to keep Staff informed, in as much detail as possible and to the extent possible, by providing an annual update that includes a status report on the progress KCPL has made in: 1) conversion of its roadway lighting to LED; and 2) evaluation of the viability of converting current area lighting technology to LED. With this agreement by KCPL, Staff makes no recommendations at this time related to LED lighting.

Staff Expert/Witness: Brad J. Fortson

D. Renewable Energy Standard - Costs

Pursuant to 4 CSR 240-20.100 (6)(D), the RES rule provides a recovery option for compliance costs. The rule provides that KCPL may:

> …recover RES compliance costs without the use of a RESRAM through rates established in a general rate proceeding. In the interval between general rate proceedings, the electric utility may defer the costs in a regulatory asset account and monthly calculate a carrying charge on the balance in that regulatory asset account equal to its short-term cost of borrowing. All questions pertaining to rate recovery of the RES compliance costs in a subsequent general rate proceeding will be reserved to that proceeding, including the prudence of the costs for which rate recovery is sought and the period of time over which any costs allowed rate recovery will be amortized.

On April 19, 2012, the Commission authorized KCPL's use of an accounting authority order in Case No. EU-2012-0131 to:

> (a) record all incremental operating expenses associated with the cost of solar rebates, the cost to purchase renewable energy credits, the cost of the standard offer and other related costs incurred as a result of compliance with Missouri's Renewable Energy Standard Law in USOA Account 182; (b) include carrying costs based on the Compan[y's] short term debt rate on the balances in those regulatory assets; and (c) defer such amounts in a separate regulatory asset with the disposition to be determined in the Compan[y's] next general rate cases.[117]

[117] *In the Matter of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company's Notice of Intent to File a Joint Application for an Accounting Authority Order Related to its Electrical Operations,* Case No. EU-2012-0131, (*Order Approving and Incorporating Stipulation and Agreement)*, at page 2.

In Case No. ER-2012-0174, a regulatory asset was established for costs incurred through August 31, 2012, and recovery of those costs was set for three (3) years. The regulatory asset defined in that case is labeled Vintage 1 and was completed in January, 2016. In compliance with the Stipulation and Agreement in Case No. ER-2014-0370, KCPL applied prospective tracking of the Vintage 1 amortization to the current RES costs deferred in Vintage 3, after full recovery of Vintage 1.

Similar to Staff's recommended treatment of other expiring amortizations, Staff recommends that once the amortization of a vintage is complete, KCPL should apply the funds that will continue to be collected in rates for the amortization of the recovered vintage to the current deferred RES program costs.

In Adjustment E-188.1, Staff has included deferred RES costs (Vintage 3) incurred through June 30, 2016, with the recovery period set at three years. As part of its True-Up audit, Staff will continue to examine RES costs through December 31, 2016, and make additional adjustments to the recovery period as needed.

Staff Expert/Witness: Matthew R. Young

XIII. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation
- J. Randall Woolridge

Appendix 3 – Other Staff Schedules

Greenwood - Additions to Plant – In-Service Criteria
- Claire M. Eubanks, PE

Recommended Depreciation Rates
- Keenan B. Patterson, PE

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

ALAN J. BAX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF MICHELLE BOCKLAGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHELLE BOCKLAGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Michelle Bocklage

MICHELLE BOCKLAGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
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State of Missouri
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D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF KORY BOUSTEAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KORY BOUSTEAD and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kory Boustead

KORY BOUSTEAD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of November, 2016.

D. SUZIE MANKIN
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State of Missouri
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D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DANA E. EAVES and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Dana E. Eaves

DANA E. EAVES

JURAT

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AFFIDAVIT OF CLAIRE M. EUBANKS, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CLAIRE M. EUBANKS, PE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks

CLAIRE M. EUBANKS, PE

JURAT

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AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CARY G. FEATHERSTONE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement-Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Cary G. Featherstone

CARY G. FEATHERSTONE

JURAT

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Notary Public

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AFFIDAVIT OF BRAD J. FORTSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BRAD J. FORTSON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brad J. Fortson
BRAD J. FORTSON

JURAT

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D. Suzie Mankin
Notary Public

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In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF TAMMY HUBER

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW TAMMY HUBER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Tammy Huber

TAMMY HUBER

JURAT

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AFFIDAVIT OF J LUEBBERT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW J LUEBBERT and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J Luebbert

J LUEBBERT

JURAT

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D Suzie Mankin

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW KAREN LYONS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Karen Lyons
KAREN LYONS

JURAT

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State of Missouri
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AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

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State of Missouri
Commissioned for Cole County
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AFFIDAVIT OF ERIN L. MALONEY, PE

STATE OF MISSOURI)
) ss:
COUNTY OF COLE)

COMES NOW ERIN L. MALONEY, PE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Erin L. Maloney, P.E.

ERIN L. MALONEY, PE

JURAT

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State of Missouri
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D. Suzie Mankin

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AFFIDAVIT OF BYRON M. MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BYRON M. MURRAY and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

BYRON M. MURRAY

JURAT

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State of Missouri
Commissioned for Cole County
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D Suzie Mankin
Notary Public

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AFFIDAVIT OF ANTONIJA NIETO

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ANTONIJA NIETO and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

A Nieto

ANTONIJA NIETO

JURAT

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Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF KEENAN B. PATTERSON, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KEENAN B. PATTERSON, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement-Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keenan B Patterson

KEENAN B. PATTERSON, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF CHARLES T. POSTON, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CHARLES T. POSTON, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

CHARLES T. POSTON, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DAVID C. ROOS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

David C. Roos

DAVID C. ROOS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHAEL L. STAHLMAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

MICHAEL L. STAHLMAN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF MICHAEL JASON TAYLOR

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW MICHAEL JASON TAYLOR and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement-Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

MICHAEL JASON TAYLOR

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF SEOUNG JOUN WON, PhD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SEOUNG JOUN WON, PhD and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Seoung Joun Won

SEOUNG JOUN WON, PhD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF J. RANDALL WOOLRIDGE

COMMONWEALTH OF PENNSYLVANIA	)	
	)	ss.
COUNTY OF CENTRE	)	

COMES NOW J. RANDALL WOOLRIDGE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement-Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J. RANDALL WOOLRIDGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Centre, Commonwealth of Pennsylvania. at my office in State College, PA, on this 23th day of November, 2016.

Notary Public

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
RONALD E FLEBOTTE
Notary Public
STATE COLLEGE BORO, CENTRE COUNTY
My Commission Expires Nov 10, 2019

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0285

AFFIDAVIT OF MATTHEW R. YOUNG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MATTHEW R. YOUNG and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Matt Young

MATTHEW R. YOUNG

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of November, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public