# MISSOURI PUBLIC SERVICE COMMISSION

# STAFF REPORT

# REVENUE REQUIREMENT
# COST OF SERVICE

## KANSAS CITY POWER & LIGHT COMPANY

## FILE NO. ER-2010-0355

*Jefferson City, Missouri*
*November 10, 2010*

** Denotes Highly Confidential Information **

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## I. Background of Great Plains Energy and Kansas City Power & Light Company

Kansas City Power & Light Company ("KCPL" or "the Company") is a corporation duly organized and existing under the laws of the State of Missouri. KCPL is a regulated public utility operating in the states of Kansas and Missouri. It provides wholesale electricity to several municipal customers under the jurisdiction of the Federal Energy Regulatory Commission (FERC). KCPL distributes and sells electric service to the public in its certificated areas in Kansas and Missouri, and is an "electrical corporation" and "public utility" subject to the jurisdiction, supervision, and control of the Commission under Chapters 386 and 393 of the Revised Statutes of Missouri. KCPL is wholly owned by Great Plains Energy ("GPE") and is an affiliate of KCP&L Greater Missouri Operations Company ("GMO," which was formerly known as Aquila, Inc. and before that UtiliCorp United, Inc.). GMO is also an "electrical corporation" and "public utility" that is subject to the jurisdiction of the Commission. KCPL and GMO collectively operate and present themselves to the public under the brand and service mark "KCP&L." GPE 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. As a holding company, GPE does not provide electric service to retail customers.

KCPL has approximately 509,000 customers of which about 450,000 are residential customers, about 57,000 are commercial customers and the remaining about 2,000 are industrial, municipal and other utility customers [source: GPE's 2009 Annual Report at page 9]. To serve these customers KCPL owns 571 megawatts (MW) of nuclear capacity, 2,309 megawatts of coal capacity (excluding Iatan 2), 100 megawatts of wind capacity, 829 megawatts of natural gas-fired combustion turbine capacity, 302 megawatts of oil fired combustion turbine capacity , and additional purchased power.

This case is the final case contemplated in KCPL's Experimental Alternative Regulatory Plan ("Regulatory Plan") which the Commission approved on July 28, 2005, in Case No. EO-2005-0329. That Regulatory Plan contemplated a series of up to four general rate increase cases designed to address the economic impacts of KCPL's planned major environmental upgrades to its LaCyne 1 and Iatan 1 generating units and the construction of a new baseload, coal-fired, generating unit designed to have 850 megawatts of capacity at KCPL's Iatan Station—Iatan 2. As part of the Regulatory Plan, KCPL committed to invest in 100 megawatts of wind-generated capacity, and to explore adding up to another 100 megawatts. KCPL satisfied its wind investment commitment in September 2006 with phase one of its Spearville Wind Farm. KCPL filed the first rate case under the Regulatory Plan on February 1, 2006 (Case No. ER-2006-0314 herein referred to as the "2006 rate case"). KCPL also filed a second case on February 1, 2007 (Case No. ER-2007-0291, herein referred to as the "2007 rate case" and a third case on September 8, 2008 (Case No. ER-2009-0089, herein referred to as the "2009 rate case").

As anticipated in the Regulatory Plan, KCPL timed the filing of this rate case so that the Iatan 2 generating unit became "fully operational and used for service" in time for KCPL's share of the prudent costs of constructing it may be included in determining KCPL's revenue requirement used to set new rates in this case. KCPL and Staff agree that Iatan 2 met the Regulatory Plan in-service criteria on August 26, 2010.

KCPL has filed for the following rate increases under the Regulatory Plan:

| Case No. | Date Filed | Amount Requested | Amount Authorized | Effective Date of Rates |
|---|---|---|---|---|
| ER-2006-0314 | February 1, 2006 | $57 million | $50.6 million | January 1, 2007 |
| ER-2007-0291 | February 1, 2007 | $45 million | $35.3 million | January 1, 2008 |
| ER-2009-0089 | September 5, 2008 | $101 million (17.5 % increase) | $95 million (16.2% increase) | September 1, 2009 |
| ER-2010-0355 | June 4, 2010 | $92.1 million (13.8% increase) | Yet to be determined | May 4, 2011 (expected) |

On April 4, 2007, GPE, KCPL, and Aquila, Inc. ("Aquila"), filed a joint application with the Missouri Public Service Commission ("the PSC" or "the Commission"), designated as Case No. EM-2007-0374 requesting approval for a series of transactions which ultimately would result in GPE acquiring Aquila's Missouri electric and steam operations, as well as its merchant services operations. These merchant services operations primarily consisted of a 340 megawatt generating facility located in Mississippi, ("Crossroads"), and certain residual natural gas contracts. The Commission approved the request of GPE, KCPL, and Aquila in an Order effective July 1, 2008. GPE acquired Aquila on July 14, 2008 and later in 2008, Aquila changed its name to KCP&L Greater Missouri Operations Company ("GMO").

*Staff Expert/Witness: Cary G. Featherstone*

## II. Executive Summary

Curt Wells, of the Commission's Utility Operations Division, and Cary Featherstone of the Utilities Services Division sponsor Staff's Cost of Service Report, Schedules and Accounting Schedules in this proceeding that are being filed concurrently with their direct testimony. Staff's Cost of Service Report, Schedules and Accounting Schedules support Staff's preliminary recommendation of the amount of the increase in rate revenues for the true-up period through December 31, 2010. However, because of significant changes expected to KCPL's cost structure occurring through the end of the year that are not known and measurable at this time, the Staff's preliminary December 31, 2010 revenue requirement will change when the true-up is completed in this case.

Staff's direct testimony presents an overview of the results of Staff's review into KCPL's cost to serve its Missouri retail customers - revenue requirement - initiated because of KCPL's general rate increase request made on June 4, 2010. Several members of the Commission Staff conducted Staff's review by examining all the relevant and material components that make up the revenue requirement calculation. These components can be broadly defined as: capital structure and return on investment; rate base investment and income statement results, including revenues; operating and maintenance expenses; depreciation expense; and related taxes, including income taxes. Staff's direct testimony provides an overview of the Staff's work on each component. Staff's Cost of Service Report and Accounting Schedules provide a detailed presentation of and support for Staff's findings based on Staff's review of KCPL's books and records, and cost of service.

As ordered by the Commission, and to timely and fairly present its direct case, Staff used actual historical information through the cut-off date of June 30, 2010, plus estimates for the impacts of the known major plant additions of Iatan 2 and KCPL's thirty-two 1.5 megawatt wind turbines it bought in February 2009 and is in the process of installing near Spearville, Kansas in what is known as Spearville 2, and an increase in KCPL's fuel costs that takes effect January 1, 2011, for analyzing KCPL's cost of service which Staff is referring to as its "Estimated True-up Case." Staff has determined Iatan 2 has met the in-service criteria of the Regulatory Plan and

Staff believes Iatan 2 is now "fully operational and used for service." Therefore, although Iatan 2 was not "fully operational and used for service" by June 30, 2010, since Staff has performed a construction audit and prudence review of Iatan Project costs based on available information using a June 30, 2010 cut-off and, therefore, has a sufficient basis to include the impacts of Iatan 2 and the associated Iatan Common Plant on KCPL's cost of service. Also, KCPL is installing new wind turbines, all or part of which, are expected to be "fully operational and used for service" by the true-up cutoff date of December 31, 2010. Staff presently has sufficient information regarding them to include the impacts of them on KCPL's cost of service. There will be other changes in KCPL's investments and costs, from June 30, 2010 to December 31, 2010, and Staff has included an estimate in its direct case to account for them. In this filing, Staff presents its analysis of KCPL's revenue requirement based on the 2009 test year updated through June 30, 2010, with Staff's estimate of the items that could easily be identified and quantified that would be addressed in the true-up. However, there are other cost increases expected to occur through December 31, 2010 that will be address only in the true-up. These will be reflected in the true-up using actual amounts for items such as payroll, payroll related benefits, pensions, and other costs. There are other plant additions besides Iatan 2 and Spearville 2 which will be in service as of December 31, 2010. These plant investments will be included in the true-up audit.

The plant addition of Iatan 2, did not meet the in-service criteria by the June 30, 2010 update cutoff but was declared in service by KCPL on August 26, 2010. Staff is in agreement that Iatan 2 has met the in-service criteria and therefore, this plant will be included in rate base for the December 31, 2010 true-up. This will result in higher plant investment requiring increases in return, depreciation expenses and operating costs such as payroll and maintenance costs. Because Iatan 2 will be the lowest cost coal-fired generating unit in KCPL's fleet, fuel costs will offset the higher operating costs. However, there is expected higher fuel costs at the end of the year which will result in an overall increase in fuel costs to KCPL.

As discussed above, it is expected that Spearville 2 will have 32 wind turbines at 1.5 megawatts each which will result in 48 megawatts of additional wind energy available to KCPL customers by years' end. KCPL plant investment will increase for this addition causing an increase in depreciation and operation and maintenance costs.

Other plant additions will be added through the time of the true-up in this case causing costs to increase. Other cost increases will likely change materially during the true-up period include payroll, payroll related benefits such as pensions and medical costs. Maintenance costs will be reflected for the Commission's new rules on vegetation management and infrastructure inspection, and repairs of the distribution and transmission system.

Staff also examined the additional amortizations from the Regulatory Plan, and the treatment of those amortizations in this rate case. The treatment of the additional amortizations is addressed in the testimony of Staff witness, Cary G. Featherstone.

The following is a non-exhaustive list of areas in Staff's direct filing:

- Rate of Return
- Reversing the Additional Amortizations KCPL obtained through its Regulatory Plan the Commission approved in Case No. EO-2005-0329 and which were re-flected in rates in KCPL's 2006 rate case (Case No. ER-2006-0314), 2007 rate case (Case No. ER-2007-0291) and 2009 rate case (Case No. ER-2009-0089)
- KCPL's investments in Iatan Unit 2, and 48 megawatts of Spearville 2 wind generation expected to be completed by the end of the year
- Remaining costs for the plant upgrades for environmental costs for KCPL investment in the Iatan 1 AQCS (Air Quality Control System) not captured in its last rate case

- KCPL's investment in Iatan Common Plant not captured in its last rate case
- KCPL's fuel costs, including freight rate increase and purchased power costs
- KCPL's off-system sales margins from the firm and non-firm bulk power markets
- KCPL's pension and other post-employment benefits (OPEBS) costs
- Jurisdictional Allocations
- Acquisition savings and transition costs
- KCPL's increase in fuel costs on January 1, 2011

*Staff Expert/Witness: Cary G. Featherstone*

## III. Construction Audit

Staff performed a construction audit/prudence review of the Iatan Project-installation of air quality control systems on Iatan Unit 1, construction of Iatan Unit 2 and construction of plant serving both Iatan Unit 1 and Iatan Unit 2 (Common Plant)-- using a cost reporting cut-off date of June 30, 2010. Staff presented the results of that audit to the Commission on November 3, 2010, in Staff's Construction Audit and Prudence Review Of Iatan Construction Project For Costs Reported As Of June 30, 2010 that Staff filed in File Nos. ER-2010-0355 and ER-2010-0356. Based on that audit Staff has quantified many of its disallowances and the major impacts of the Iatan Project on Staff's true-up revenue requirement recommendation for KCPL; therefore, Staff is addressing them and relying on them for its current Estimated True-up Case revenue requirement recommendation for KCPL. In addition to the Iatan Project, KCPL is adding 32 1.5 megawatt wind turbines to its generation plant that are expected to be "fully operational and used for service" by December 31, 2010, and KCPL will have other plant additions and changes that will be fully captured in the true-up. Staff witness Charles R.

Hyneman addresses the construction audit in his direct testimony being filed concurrently in this case.

*Staff Expert/Witness: Cary G. Featherstone*

## IV. Kansas City Power and Light Company's Rate Case Filing

KCPL filed its general rate increase case on June 4, 2010, reflecting an annual increase in Missouri retail rate revenues of $92.1 million. This request represents a proposed 13.8% increase. The Commission designated this rate case as File No. ER-2010-0355. KCPL proposes a rate of return on equity of 11.0% applied to the 46.16% equity capital structure for GPE [paragraph 15 of KCPL Minimum Filing Requirements].

GMO also filed a rate case on June 4, 2010, for its electric operations. This case has been designated as File No. ER-2010-0356. GMO has different rates in two different areas – one in and about Kansas City, which was formerly served under the d/b/a Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as "MPS" and "L&P" in this report. For MPS, GMO has identified its rate revenues increase in the amount of $78.8 million, representing a 14.4% increase. For L&P electric service, GMO states it is requesting an increase in rate revenues in the amount of $22.1 million, representing a 13.9% increase. These GMO requests are based on a proposed rate of return on equity of 11.0% applied to the 46.16% equity capital structure for GPE [paragraph 8 of GMO Minimum Filing Requirements].

*Staff Expert/Witness: Cary G. Featherstone*

### A. Test Year

As the Commission ordered, the test year in this case, as well as the GMO case for MPS and L&P, is the 12-month period January 1, 2009, through December 31, 2009, updated for known and measurable changes through June 30, 2010, and trued-up through December 31, 2010.

*Staff Expert/Witness: Cary G. Featherstone*

### B. Estimated True-up Case

Because of the significant plant additions of Iatan 2 and 32 new 1.5 megawatts wind turbines near Spearville, Kansas, anticipated by the end of 2010, at KCPL's request the Commission established a true-up through the end of December 31, 2010. While no party disputed using a 2009 test year, not all parties agreed to the update and true-up periods. In its August 18, 2010 Order where it set the procedural schedule in this case, the Commission said the following regarding the true-up:

> A true-up period of the 12 months ending December 31, 2010, and Iatan 2 and Iatan Common Plant cutoff period of October 31, 2010, is ordered, assuming that the actual in-service date of Iatan 2 is projected to occur no later than December 31, 2010. However, in the event that the in-service date of Iatan 2 is projected to be delayed beyond December 31, 2010, the true-up period would be moved to the last day of the same calendar month as the actual in-service date of Iatan 2 and the Iatan Common Plant cutoff period would be moved to two months prior the revised true-up date…
>
> If the true-up period is adjusted, Kansas City Power & Light Company shall extend the effective date of its tariffs four months past the end of the true-up period; however, such adjustment shall not extend beyond an in-service date for Iatan 2 of March 31, 2011.
>
> Kansas City Power & Light Company shall indicate by filing a pleading no later than October 6, 2010 if it seeks to adjust the true-up period.
>
> [Commission Order issued August 18, 2010, pages 2-3]

Thus, the Commission authorized that the true-up in this case be through December 31, 2010, unless an extension becomes necessary as a result of the Iatan 2 construction project currently undertaken by GPE and its subsidiaries. KCPL notified the Commission on October 6, 2010 that "the Companies hereby notify the Commission that they do not seek to extend the true-up period in these cases beyond the December 31, 2010 date established in the Procedural Order." Therefore, the true-up in this case, as well as the GMO rate case, will be through December 31, 2010.

*Staff Expert/Witness: Cary G. Featherstone*

## V. Rate of Return Section

### A. Introduction

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

**TABLE ONE: KCPL'S ROR:**

| | | | Weighted Cost of Capital Using Common Equity Return of: | | |
|---|---|---|---|---|---|
| Capital Component | Percentage of Capital | Embedded Cost | **8.50%** | **9.00%** | **9.50%** |
| Common Stock Equity | 47.65% | ----- | 4.05% | 4.29% | 4.53% |
| Preferred Stock | 0.65% | 4.291% | 0.03% | 0.03% | 0.03% |
| Long-Term Debt | 47.12% | 6.825% | 3.22% | 3.22% | 3.22% |
| Equity Units | 4.59% | 11.140% | 0.51% | 0.51% | 0.51% |
| Total | **100.00%** | | **7.80%** | **8.04%** | **8.28%** |

*See Schedule 16*

As contained in Table One, Staff recommends, based upon its expert analysis, a return on common equity ("ROE") of range of 8.50% to 9.50% and an overall ROR of 7.80% to 8.28% with a mid-point ROE and ROR of 9.00% and 8.04%, respectively. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-16. Additionally, with the exception of sources in which Staff simply extrapolated data and textbook references, supporting articles and/or reports are attached as Appendix 2, Attachments A - H. If the Commission discovers any additional supporting documentation it desires the Staff to provide, Staff will do so upon the Commission's request.

### B. Analytical Parameters

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

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

> low by changes affecting opportunities for investment, the money market and business conditions generally.

Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*, the Court stated:[1]

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

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

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

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

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[2] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of

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[1] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

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

risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return KCPL's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific DCF method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[3] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for KCPL.

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

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

## C. Current Economic and Capital Market Conditions

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

### 1. Economic Conditions

The United States is presently emerging from the most severe recession since the Great Depression (*see* Appendix 2, Attachment A).[4] Although the economy is now again expanding, growth is projected to be low for the next couple of years (*see* Appendix 2, Attachment B).[5] As a result, economists generally expect the long-term Gross Domestic Product ("GDP") growth rate to be in the range of 4% to 5%, of which approximately 2.0% is attributed to inflation.[6]

Because of the Federal Reserve Bank's ("Fed") concerns about the possibility of a "double-dip" recession and deflation, the Fed continues to maintain the Fed Funds Rate at historically low levels between 0.00% and 0.25% (*see* Appendix 2, Schedules 2-1 and 2-2). Additionally, the Fed has pledged to embark on a bond buy-back program in order to provide continued liquidity to the financial system.

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[4] Sara Murray, "Slump Over, Pain Persists: Bureau Calls End to Recession, Longest Since 1930s; Jobs Recovery Still Slow," *The Wall Street Journal*, September 21, 2010, pp. A1 and A2.

[5] Jon Hilsenrath and Luca Di Leo, "Fed Hints at Move to Boost Recovery," *The Wall Street Journal*, September 22, 2010, p. A2.

[6] The Congressional Budget Office (CBO), *The Budget and Economic Outlook: Fiscal Years 2010-2020,* August 2010; and The Energy Information Administration's *2010 Annual Energy Outlook*.

An example of investors' current low required real returns due to the current economic situation can be derived from the US Treasury's October 25, 2010 issuance of $10 billion of 5-year Treasury Inflation Protected Securities ("TIPS") at a yield of "-0.55"% (*see* Appendix 2, Attachment C).[7] According to the article cited below, this is the first time TIPS have ever been sold at a *negative* real return. This negative real return implies that investors' return requirements are not related to growth, but to the possibility of an inflation offset to produce positive returns. If the inflation premium of 1.88% (1.33% 5-year Treasury rate less the negative 0.55% TIPS rate) is realized, then the TIPS investors will realize a total return equivalent to that of the 5-Year Treasury.

## 2. Capital Market Conditions

### a. Utility Debt Markets

Utility debt markets clearly indicate a lower cost-of-capital environment. If one were to assume that the risk premium[8] required to invest in utility stocks rather than utility bonds were constant, then these lower utility debt yields clearly translate into a lower required return on equity. In other words, a lower cost of debt is indicative of a lower cost of capital, all else equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Long-term interest rates, as measured by 30-year Treasury bonds ("T-bonds"), have decreased in recent months. The daily yield on 30-month Treasury bonds was 3.87% in October 2010, one of the lowest average yields since April 2009 (*see* Appendix 2, Schedules 4-2 and 4-3). Long-term utility bond yields have also declined in this cycle, contrary to what occurred in the last cycle, dropping to a 40-year low in October 2010 of 5.14% (*see*

[7] Mark Gongloff and Deborah Lynn Bluberg, "Yields on Tips Go Negative: Big Demand for Bonds Suggests Fed is Winning Deflation Battle; It 'Is Striking'" *The Wall Street Journal;* October 26, 2010, pp. C1 and C2.

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

Appendix 2, Schedules 4-1 and 4-3). As of October 2010, the average spread between 30-year T-bonds (3.87%) and average utility bond yields (5.14%)[9] was 127 basis points, which is 27 basis points below the average such yields displayed in the period since 1980 (*see* Appendix 2, Schedule 4-4). Recent utility bond yields have dropped to levels not experienced since the 1960s.[10]

While the cost of investment-grade utility debt capital has reached historic lows, the risk premium to invest in bonds of lower credit quality is higher than it was prior to the financial crisis of late 2008 and early 2009. Thus, while utilities with at least investment grade credit ratings can obtain capital quite cheaply, utilities with lower credit quality will pay a higher risk premium relative to risk-free rates than they did before the fall of 2008. However, the total required return on even borderline investment-grade debt is at levels not seen in at least 40 years.

The present low cost of utility capital is illustrated by the case of The Empire District Electric Company, which recently announced the issuance of $50 million of 30-year First Mortgage Bonds at a coupon of 5.20%, which will be used in part to redeem debt with a coupon of 7.05% maturing in 2022. Additionally, Empire was able to issue 10-year First Mortgage Bonds at the favorable rate of 4.65% last May, despite its lower S&P corporate credit rating of "BBB-."

**b. Utility Equity Markets**

Over the nine months ending September 30, 2010, the total return on the Dow Jones Industrial Average was 5.6%, the total return on the Standard & Poor's 500 was 3.9%, and the

[9] The 5.08% yields is based on an average from data obtained from BondsOnline.com. For utility bond yields cited by Staff prior to September 2010, Staff used Mergent Bond Record. Staff has canceled its subscription to Mergent Bond Record and will rely on data it receives from BondsOnline pursuant to a subscription agreement.

[10] Because Staff does not have utility bond yield data dating back to the 1960s, this is based on Staff's review of general corporate bond yields that were available from the St. Louis Federal Reserve website. This data showed that the general level of bond yields was much lower in the 1960s.

total return on the Edison Electric Institute ("EEI") Index of electric utilities was 5.6% (*see* Appendix 2, Attachment D). More specifically on a non-market capitalization weighted basis, the total return for the nine months ended September 30, 2010 was 10.5% for EEI "Regulated" electric utilities, 7.0% for EEI "Mostly Regulated" electric utilities and -4.9% for "Diversified" electric utilities. Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely to be more affected by general economic trends. The higher total return for "Regulated" electric utilities compared to broader markets and "Diversified" electric utilities implies that investors do not expect a significant economic recovery in the near future. Consequently, assuming investors in "Regulated" electric utilities have not increased their growth expectations for the regulated utility sector, these higher returns imply a decrease in the cost of equity for "Regulated" electric utilities.

## D. KCPL's and GPE's Operations

The following excerpt from GPE's Form 10-K filing with the SEC for the 2009 calendar year provides a good description of GPE's current business operations:

> Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:
>
> - KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company).
>
> - KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that primarily provides electricity to customers in the state of Missouri. GMO also provides regulated

steam service to certain customers in the St. Joseph, Missouri area. GMO wholly owns MPS Merchant Services, Inc. (MPS Merchant), which has certain long−term natural gas contracts remaining from its former non−regulated trading operations.

- Great Plains Energy Services Incorporated (Services) obtains certain goods and third−party services for its affiliated companies.

- KLT Inc. is an intermediate holding company that primarily holds investments in affordable housing limited partnerships.

Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 23 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).

The electric utility segment consists of KCP&L, a regulated utility, and, since the July 14, 2008, acquisition date of GMO, GMO's regulated utilityoperations which include its Missouri Public Service and St. Joseph Light & Power divisions. Electric utility serves over 820,000 customers located in western Missouri and eastern Kansas. Customers include approximately 724,000 residences, 95,000 commercial firms, and 2,300 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 85% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one−third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 104%, 119% and 130% of Great Plains Energy's income from continuing operations in 2009, 2008 and 2007, respectively.

Although GMO is a separate subsidiary corporation of GPE, it does not file separate financial statements with the Securities and Exchange Commission ("SEC"). To date, GMO has not directly issued any debt financing since being acquired by GPE. In March 2009, KCPL issued $400 million in secured debt. GPE has issued financing, such as the equity units, that has been used by both KCPL and GMO.

### E. KCPL, GPE and GMO's Credit Ratings

KCPL, GPE and GMO are currently rated by Moody's and S&P. It is important to understand the current credit standing of the various entities, as these ratings influence investors' views of the risk associated with investing in KCPL. Although Staff is not estimating the cost of capital for GMO and/or GPE in this case, the influence of the risks of these entities on KCPL's risk must be understood in order to estimate a fair rate of return for KCPL.

KCPL's Moody's senior unsecured credit rating is 'Baa2', (*see* Appendix 2, Attachment E) and its S&P senior unsecured credit rating is 'BBB', (*see* Appendix 2, Attachment F), which are considered equivalent credit ratings based on each rating agency's ratings system. The difference between the two rating agencies ratings opinions lie in how they view the credit rating of GPE and GMO. Moody's assigns GPE's and GMO's senior unsecured debt a rating of 'Baa3', which is one notch lower than that of KCPL. S&P, on the other hand, assigns GMO's senior unsecured debt the same rating as that of KCPL. However, S&P assigns GPE's senior unsecured debt a rating one notch lower than that of KCPL and GMO. A key difference in the rating methodologies between S&P and Moody's is in the amount of weight that each agency gives to the stand-alone subsidiary business and financial risks in assigning ratings. S&P tends to rate most companies based on the consolidated risk profile of the parent company, whereas Moody's tends to give at least some weight to the stand-alone subsidiary risk profile in rating the subsidiary's credit risk.

The following is an excerpt from an April 30, 2010, S&P credit-rating report on KCPL:

> The ratings on Kansas City Power and Light Co. (KCP&L) reflect the consolidated credit profile of Great Plains Energy Inc. Great Plains' regulated subsidiaries include KCP&L and KCP&L Greater Missouri Operations Co. (GMO). The ratings also reflect the company's 'excellent' business risk profile and 'aggressive' financial risk profile. As of Dec. 31, 2009, the Kansas City-based Great Plains had about $3.7 billion of total debt outstanding.

> Through its regulated subsidiaries, Great Plains distributes electricity to about 820,000 customers in Kansas and Missouri. The company's electric generating capacity is approximately 6,100 megawatts (MW), and in 2009 about 80% of the energy generated was from coal and 17% from nuclear.
>
> The 'excellent' business risk profile reflects the company's pure regulated strategy, our view of the company's decreasing regulatory risk, and management's renewed commitment to credit quality. In 2009 the Kansas and Missouri Commissions ordered various constructive rate orders, increasing rates by a total of $218 million, or about 85% of what Great Plains originally requested. Additionally, we view the regulatory mechanisms including the fuel adjustment clauses for GMO and KCP&L (in Kansas only), and the allowance of additional accelerated depreciation to be credit supportive. Also in 2009, the company proactively reduced its dividend and issued equity, demonstrating its renewed commitment to credit quality . . .

In its March 17, 2010, Credit Opinion on KCPL, Moody's provided the following "Rating Rationale" in its comments:

> KCPL's Baa2 senior unsecured rating is based on its historical ability to achieve good levels of cash flow from its regulated utility operations in Missouri and Kansas. However, the company has and continues to face challenges including weakness in credit metrics, a need to maintain generating fleet operational efficiency, the achievement of wholesale power sales targets, and managing the stress that increased environmental expenditures and the large capital expansion program at Iatan 1 & 2 have placed on the company's balance sheet. The combined pressures of these challenges were primary drivers of the March 2010 downgrade of KCPL's unsecured rating. The notching of KCPL's A3 senior secured rating is consistent with Moody's implementation of a widening of the notching between most senior secured debt ratings and the senior unsecured debt ratings or Issuer Ratings of investment grade regulated utilities to two notches from one previously.
>
> The historical reliance that KCPL's parent has placed on the company as a source of dividends has also been a rating consideration. This may be offset somewhat with the acquisition of GMO and the 2009 dividend cut but we note that on a stand-alone basis GMO continues to exhibit a more leveraged capital structure than KCPL which continues to be a consideration in our ratings. We note Great Plains provides a downstream guarantee of the unsecured debt at GMO.

Although Moody's does indirectly consider the impact that GMO has on the credit risk of KCPL, Moody's consideration is not as direct as S&P's because S&P's ratings methodology only evaluates GPE's consolidated financial ratios when assigning a credit rating to both KCPL and GMO. S&P does not rate KCPL's and GMO's debt on a stand-alone basis because of S&P's view that the subsidiaries are not operating as stand-alone entities from a credit risk perspective. Due to the fact that S&P does not view these entities as stand-alone entities from a credit risk perspective, it is a matter of speculation on what KCPL's cost of capital might have been absent its affiliation with GMO. However, because it is important to ensure that KCPL ratepayers do not pay a higher cost of capital due to higher financial risks associated with GPE's acquisition of GMO, it is important to carefully evaluate each capital issuance included in KCPL's ratemaking capital structure to determine if any adjustments should be made to the costs of these capital components. It is Staff's view that if these higher capital costs are included KCPL's ROR, this would be a violation of the Commission's Report and Order issued in Case No. EM-2007-0374.

## F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically examined (1) an appropriate ratemaking capital structure, (2) the Company's embedded cost of debt, (3) the Company's embedded cost of preferred stock, (4) the cost of short-term debt (if included in the capital structure) and, (5) any other unique Company-specific capital components, and finally, (6) the Company's cost of common equity.

### 1. Capital Structure

Appendix 2, Schedule 5 presents GPE's historical capital structures in dollar terms and percentage terms for the past five years. As can be derived from these historical capital structures, the current capital structure of GPE is somewhat consistent with the way in which it has been capitalized for the last two years, but not for the previous three.

GPE has limited the amount of common equity it has issued for capital expenditure needs in 2008 and 2009 due to GPE's lower common share price than in previous years. It should also be noted that the amount of debt included in GPE's 2009 year-end capital structure included $287,500,000 of equity units (to be discussed in further detail in later sections). If GPE had issued traditional common equity in the amount of $287,500,000, its common equity ratio in 2009 would have been 47.51% rather than 43.08%.

Staff believes that the consolidated-basis capital structure of KCPL's publicly-traded parent, GPE, as of June 30, 2010, the end of the updated test year, is most appropriate for use as the rate making capital structure in this rate proceeding. *See* Appendix 2, Schedule 6. This capital structure is appropriate because it reflects KCPL's actual financing and because the risk embedded in GPE's capital structure affects KCPL's credit rating. However, as Staff explained previously, embedded costs of capital issued subsequent to GPE's acquisition of GMO should be reviewed for possible risk adjustments due the increased risk associated with legacy GMO debt. Staff's recommended KCPL ratemaking capital structure consists of 47.65% common equity, 47.12% long-term debt, 4.59% equity units and 0.65% preferred stock.[11]

### **2. Embedded Cost of Debt**

In prior KCPL rate cases Staff has recommended using GPE's consolidated embedded cost of long-term debt for purposes of its recommended ROR for KCPL. However, recommending the consolidated embedded cost of long-term debt for KCPL in this rate case would result in GMO's debt being included in this cost, which could arguably result in a violation of the Commission's Report and Order issued in Case No. EM-2007-0374. This Report and Order required that KCPL ratepayers not be charged higher rates due to higher capital costs

[11] KCPL's response to Staff DR No. 194 and SEC 2009 10-K Filing.

as result of the acquisition of the GMO properties. While Staff continues to believe that matching the consolidated capital structure with the consolidated cost of debt is ideal, Staff does not believe it is appropriate in this case because of the uncertainty involved in evaluating GMO's cost of debt. After excluding GMO's cost of debt, GPE's embedded cost of long-term debt as of June 30, 2010, was 6.825% (KCPL's updated response to Staff Data Request No. 194). Consistent with Staff's explanation above, this is the cost of long-term debt embedded in Staff's ROR recommendation for KCPL.

### 3. Embedded Cost of Preferred Stock

Due to the fact that the preferred stock was issued by KCPL prior to GPE's acquisition of the GMO properties, it is reasonable to include both the amount and cost of preferred stock in KCPL's allowed rate of return. Staff has reviewed KCPL's calculation of KCPL's embedded cost of preferred stock of 4.291% and finds both the cost and calculation to be reasonable and accurate.

### 4. Embedded Cost of Equity Units

Although Staff accepts KCPL's calculation *methodology* used to determine the embedded cost of the above-mentioned equity units, Staff believes that the *cost* of the equity units is unreasonable in that the required return on the equity units was higher due to GPE's strained credit quality resulting from its acquisition of the GMO properties. Consequently, Staff believes that a downward adjustment should be made to the cost of this capital component.

In order for the Commission to evaluate whether an adjustment should be made to the cost of the equity units, it is important for the Commission to have a basic understanding of this type of capital and the reasons it may be issued. Although this capital is identified as an "equity" unit, it is not reported as equity on GPE's balance sheet. It is reported as debt because the equity unit represents a 5% undivided beneficial interest in $1,000 principal amount of subordinated debt with a 10% coupon, and a purchase contract requiring the holder to purchase GPE's common stock at a predetermined settlement rate by June 15, 2012. At the time of this purchase, the $287,500,000 of subordinated debt would be reclassified as common equity, but GPE may remarket the subordinated debt to raise additional financing through debt capital.

Because the equity units consist of subordinated debt issued by GPE, the cost is directly impacted by GPE's credit quality, which has been negatively impacted by its acquisition of the former Aquila Missouri electric utility properties (GMO). Although the negative impact of the acquisition on GPE's credit quality would have caused a higher cost of capital under normal capital market conditions, this negative impact was magnified by the timing of the issuance in May 2009, a time when investors required a significant risk premium to invest in companies that were borderline investment grade. At the time of the issuance of the equity units GPE's senior unsecured credit rating was a 'BBB-'. Although GPE's credit rating was never downgraded due to its acquisition of GMO, Staff believes that its credit rating has definitely been suppressed because of the strain that GMO's legacy debt has placed on GPE's consolidated ratios. This is troublesome considering the fact that KCPL was allowed to charge higher rates, through "additional amortizations, i.e. additional cash flow, to support benchmark credit metrics that were consistent with the benchmarks for a 'BBB+' credit rating. Staff believes it is appropriate to adjust the cost of the equity units downward to a level that would have been more consistent with the financial risk profile that ratepayers supported during the period of its experimental alternative regulatory plan.

Just as with estimating the cost of common equity, estimating what the cost of any type of capital might have been given a different risk profile requires some judgment. Just as with the estimation of the cost of equity it is usually reasonable to look to proxy companies to impute what the cost of the equity units could have been if KCPL's cost of capital was not influenced by the impact of the GMO legacy debt on GPE's consolidated credit quality. Additionally, because the equity units were issued in May 2009 (a time in which the additional cost to issue capital for a 'BBB-' entity compared to a 'BBB+' was higher than usual) it is important to look at equity units issued by other utility holding companies at approximately the same time. Staff was only able to find one utility holding company that issued equity units during the same approximate period. FPL Group issued equity units in May 2009 at a cost of 8.375%, which was 3.625% lower than the 12% that GPE paid. FPL Group had a senior unsecured rating at the time of 'A-', which is three notches higher than GPE's senior unsecured rating. Although the required return for each notch increase in credit rating typically increases at a decreasing rate (meaning that Staff's adjustment will probably be underestimated), Staff assumed that each notch required an additional 1.21% return (3.625/3). Consequently, Staff made a 2.42% downward adjustment to GPE's equity unit coupon rate of 12%, which resulted in an adjusted embedded cost of the equity units of 11.14%. While this cost still seems relatively high, the timing of the issuance of the equity units was during a period of much uncertainty in the market. For example, in the most recent AmerenUE rate case, File No. ER-2010-0036, AmerenUE's embedded cost of debt included a 30-year First Mortgage Bond issued in March of 2009 with a coupon of 8.45%. This compares to Empire's recent issuance of a 30-year First Mortgage Bond at a rate of 5.20%, which was issued only slightly over a year later than AmerenUE's bond.

## 5. Cost of Common Equity

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

### a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 61 market-traded electric utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to KCPL's regulated electric utility operations (*see* Appendix 2, Schedule 7):

1. Classified as an electric utility by Value Line (61 companies);
2. Publicly-traded stock;
3. Classified as a regulated utility by EEI or not followed by EEI (26 companies eliminated, 35 remaining);
4. At least 70% of revenues from electric operations or not followed by AUS (10 companies eliminated, 25 remaining);
5. Ten years of Value Line historical growth data available (3 companies eliminated, 22 remaining);
6. No reduced dividend since 2007 (5 companies eliminated, 17 remaining);
7. Projected growth available from Value Line and Reuters (2 companies eliminated, 15 remaining);
8. At least investment grade credit rating (2 companies eliminated, 13 remaining);
9. Company-owned generating assets (2 companies eliminated, 11 remaining); and
10. Significant merger or acquisition announced in last 3 years (1 company eliminated, 10 remaining).

This final group of 10 publicly-traded electric utility companies ("the comparables") was used as a proxy group to estimate the cost of common equity for KCPL's regulated electric utility operations. The comparables are listed on Appendix 2, Schedule 8.

**b. The Constant-growth DCF**

Next, Staff calculated KCPL's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[12] [13] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: $k$ is the cost of equity;

$D_1$ is the expected next 12 months dividend;

$P_0$ is the current price of the stock; and

$g$ is the dividend growth rate.

The term $D_1/P_0$, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the weighted average of the 2010 (25%) and 2011 (75%) Value Line projected dividends per share (*see* Schedule 11) by the monthly high/low average stock price for the three

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

[13] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p.64.

months ending September 30, 2010 (*see* Schedule 10).[14] Staff weighted the Value Line projections in this manner in order to reflect the approximate amount of time remaining in 2010. Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.7%, unadjusted for quarterly compounding.

**i. The Inputs**

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share ("DPS"), earnings per share ("EPS") and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite volatile.[15] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 9-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 9.50%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 11.80%. The average projected 5-year EPS growth rate yielded a non-sustainable growth rate of 5.97% (*see* Schedule 9-4, Column 6).

Due to the current volatility and wide dispersions present in Staff analysis of historical and projected DPS, EPS, and BVPS, Staff considered none of those methods to produce reliable

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

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

indicators of long-term growth expectations. For this reason, Staff selected an alternative input, based upon Staff's expertise and understanding of current market conditions. Staff used a growth rate range of 4.0% to 5.0% in its constant-growth DCF, although Staff does not consider that figure to be sustainable for the electric utility industry in the long run. Since World War II, electric utility growth rates have been approximately half of achieved GDP growth. As noted previously, long-term GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities may be approximately 2.25%.

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 4.7% and a growth rate range of 4.0% to 5.0% -- Staff has estimated KCPL's cost of common equity at 8.7% to 9.7% (*see* Schedule 11).

**c. The Multi-stage DCF**

**i. Overview**

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[16] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for KCPL.

A multi-stage DCF may use either two or three growth stages, depending on the situation being modeled. In either case, the last stage must use a sustainable rate as it is considered to last into perpetuity. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate estimate for the

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

final stage because this growth is assumed to grow in perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[17]

In the present case, Staff used a three-stage DCF approach, the stages being years 1-5, years 6-10, and years 11 to infinity.[18] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 13-1 through 13-3).[19] Based on this set of assumptions, Staff's estimated cost of equity for the proxy group is approximately 8.70% to 9.40%, mid-point of 9.05%. Using the mid-point of Staff's assumed range of perpetual growth rates results in an estimated cost of equity of approximately 9.00%.

**ii Stage one**

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly

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

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

[19] The approximate 50-year average DPS, EPS and BVPS growth rate for the electric industry calculated from data in the Mergent *Public Utility and Transportation Manual,* 2003 edition. This is higher than the likely true sustainable growth rate of 2.25% explained above.

to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for purposes of estimating the growth in DPS in a single-stage constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analysis should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

**iii. Stage two**

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

**iv. Stage three**

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

Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. For example, if Staff had assumed that its comparable companies could grow into perpetuity at the same rate as the average 5-year EPS growth rates of approximately 6.00%, Staff's cost of equity estimate would have been approximately 10.85%. Just as with the constant-growth DCF analysis, the assumed growth rate for the "constant stage" is the most critical component of a DCF cost of equity estimate. Consequently, Staff will explain in further detail Staff's assumed perpetual growth rate range of 3.00% to 4.00% and will test this perpetual growth rate for reasonableness.

### v. Electric Utility Industry Long-term Growth Rates

In the last KCPL and GMO rate cases, Staff estimated the perpetual growth rate based on expected long-term growth in demand for electricity plus an expected inflation factor. Although Staff still considers this to be a sound approach and consistent with how investors evaluate growth expectations, because the Commission's Report and Order in the AmerenUE rate case, File No. ER-2010-0036 indicated that the Commission believed this approach was inconsistent with the requirements of the DCF methodology because it does not directly consider EPS and/or DPS growth, Staff has researched additional data to estimate an electric utility industry long-term average EPS and DPS growth rate. Appendix 2, Schedule 14 attached shows actual realized long-term growth over an approximate 50-year period. Staff calculated an average of rolling 10-year compound average historical growth rates using the Value Line approach, which calculates growth rates based on an average of 3-years of financial data to smooth out any abnormalities. Based on this data, there is no plausible reason to believe that investors would expect a perpetual growth rate for the electric utility industry to be much higher than 3.0 to 4.0%. These growth rates were less than 50% of the growth in nominal GDP of 7.53% over the same period. If electric utilities' EPS and DPS continue to grow at approximately half of expected nominal GDP growth, then investors are more likely to expect a perpetual growth rate in the 2.0% to 3.0% range.

### vi. Perpetual Growth Rates Used in Investment Analysis

Goldman Sachs generally assumes a perpetual growth rate of 2.5% when performing a DCF analysis of regulated electric utility companies (*see* Appendix 2, Attachment G).[20] If Staff had assumed a perpetual growth rate of approximately 2.5% in its multi-stage DCF analysis, Staff's estimated cost of equity would have been approximately 8.3%.

Additionally, one of the financial advisors hired by Aquila to provide a "Fairness Opinion" on a fair price to pay for the GMO properties provided their assumed perpetual growth rates in publicly-available documents filed with the SEC[21]. Blackstone Advisory Services L.P. ("Blackstone") estimated an implied perpetual growth rate of 3.4% to 4.8% for Aquila's (GMO's) cash flows after 2013. Blackstone estimated an implied perpetual growth rate of 1.7% to 3.2% if Strategic Energy[22] was excluded and 1.7% to 3.4% if Strategic Energy was included. While estimated perpetual growth rates may change slightly over time due to shifts in expected economic and/or industry growth, Staff believes these provide a fair test of reasonableness of perpetual growth rates in a multi-stage DCF analysis or even a constant-growth DCF analysis for that matter. However, just as recent economic and financial events may have impacted the risk premiums investors require to invest in riskier investments, these events have probably also impacted investors views regarding potential long-term growth rates. Consequently, Staff believes that the perpetual growth rates used by these financial advisors would be lower if they were to perform their analysis in the current environment.

[20] Michael Lapides, Zac Hurst and Jadieep Malik, *Company Update: Great Plains Energy*, "Financing NT needs outweigh valuation on normalized LT earnings," March 2, 2009, p. 6.

[21] Although the other advisors did not provide this information in publicly-available documents, Staff will request this information from KCPL as the case proceeds.

[22] Strategic Energy consisted of GPE's former non-regulated retail energy marketing operations that were divested when GPE acquired Aquila's Missouri regulated electric utility operations, which are currently held at KCP&L Greater Missouri Operations.

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

#### vii. Commission Preference for GDP Growth

Finally, although Staff does not believe the use of long-term GDP growth is an appropriate proxy for the perpetual growth rate for electric utilities, Staff does recognize that the Commission indicated a preference for this proxy in its Report and Order in File No. ER-2010-0036. In its Report and Order the Commission stated a preference to use historical GDP growth from 1929 through 2008 to derive an expected growth rate of 6.0% for the economy. Although Staff does not recommend the Commission use GDP as a proxy for perpetual growth in this case, if the Commission should choose to do so, Staff advises the Commission to use growth rates that are consistent with long-term projections for GDP growth in the current economic environment. This growth rate would be approximately 4.5% based on various projections available. If Staff makes this assumption in its multi-stage DCF analysis, then the estimated cost of equity is approximately 9.75%.

## G. Tests of Reasonableness

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

### 1. The CAPM

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

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

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

For inputs, Staff relied on historical capital market return information through the end of 2009. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending September 30, 2010; that figure was 3.85%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 12). The average beta ("β") for the proxy group was 0.65. For the market risk premium ("Rm – Rf"), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.[23] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2009, which was 6.00%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2009, which was 4.40%.

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

Staff's CAPM is presented on Schedule 12. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.72% and 6.69%, respectively. These low cost of common equity results support the reasonableness of Staff's higher cost of equity estimates from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the early 1960s) and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 7% to 8% range for utility stocks.

### 2. Other Tests

#### a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity ("YTM") of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4% range.[24] Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of July, August and September 2010, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 5.14% and 5.71% respectively.[25] Adding a 3% risk premium, the "rule of thumb" predicts a cost of common equity between 8.14% and 8.71%. Adding a 4% risk premium, the "rule of thumb" predicts a cost of common equity between 9.14% and 9.71%.

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

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

### b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using the average authorized returns published by Regulatory Research Associates ("RRA") as a benchmark. According to RRA, (*see* Appendix 2, Attachment H), the average authorized cost of common equity for electric utility companies for the first three quarters of 2010 was 10.36% based on 43 decisions (first quarter – 10.66% based on seventeen decisions; second quarter – 10.08% based on fourteen decisions; third quarter – 10.27% based on twelve decisions). The average authorized cost of common equity for electric utility companies for 2009 was 10.48% based on 39 decisions (first quarter – 10.29% based on nine decisions; second quarter – 10.55% based on ten decisions; third quarter – 10.46% based on three decisions; fourth quarter – 10.54% based on seventeen decisions).

Staff notes that, while its recommended cost of common equity for KCPL is below the average authorized returns reported by RRA, the ROR calculated using Staff's recommendation is in line with the reported average authorized ROR for the first three quarters of 2010. The average authorized ROR for electric utilities for the first three quarters of 2010 was 8.01% based on 25 decisions (first quarter – 7.95% based on seventeen decisions; second quarter – 7.95% based on fifteen decisions; third quarter – 8.17 based on thirteen decisions). The average authorized ROR for electric utilities in 2009 was 8.23% based on 38 decisions (first quarter – 8.19% based on eight decisions; second quarter – 8.05% based on nine decisions; third quarter – 8.48% based on three decisions; fourth quarter – 8.30% based on eighteen decisions).

Additionally, the fact that Staff's recommended ROR is similar to average authorized RORs even though Staff's recommended ROE is lower than average authorized ROEs implies that KCPL's embedded costs of capital are higher than average. KCPL's higher embedded costs of capital can be attributed to both the costly equity units and also to a higher embedded cost of debt than KCPL typically has had in past rate cases.

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

### H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover KCPL's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for KCPL in the range of 7.80% to 8.28% (*see* Schedule 16). This rate was calculated by applying an embedded cost of long-term debt of 6.825% and a cost of common equity range of 8.50% to 9.50% to a capital structure consisting of 47.65% common equity, 47.12% long-term debt, 0.65% preferred stock and 4.59% equity units. Staff urges the Commission to accept its recommendation and in order to allow KCPL to earn a fair return on its net rate base.

# VI. 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 update period, June 30, 2010. This includes plant additions that have occurred since the test year ending December 31, 2009, and the related depreciation reserve balances. At the time of the true-up, 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 during the period of June 30, 2010, through December 31, 2010, the true-up cut-off date. Staff will also make a true-up adjustment to update for depreciation reserve balances related to those additions. 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, 2010 is identified on the Plant Schedule 3 and the accumulated depreciation reserve as of that date is identified in the Depreciation Reserve Schedule 6.

During the analysis of KCPL's plant reserve balances, Staff found KCPL had made adjustments to the reserve account balances for retirement work in progress ("RWIP").[26] KCPL removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates, but, as of June 30, 2010, had not removed the related reserve for cost of removal and salvage. As a result, KCPL's books overstate the reserve for this retired plant; therefore, Staff made an adjustment to remove from the reserve balances the plant that was no longer being used for service. Staff included a line item in the Accumulated Depreciation Schedule identifying the RWIP associated with Production, Transmission, Distribution and General Plant.

| Load | Unit | Year Completed | Estimated 2010 MW Capacity | Primary Fuel |
|---|---|---|---|---|
| Base Load | Wolf Creek | 1985 | 545(a) | Nuclear |
| | Iatan No. 1 | 1980 | 494(a) | Coal |
| | LaCygne No. 2 | 1977 | 341(a) | Coal |
| | LaCygne No. 1 | 1973 | 368(a) | Coal |
| | Hawthorn No. 5(b) | 1969 | 563 | Coal |
| | Montrose No. 3 | 1964 | 176 | Coal |
| | Montrose No. 2 | 1960 | 164 | Coal |
| | Montrose No. 1 | 1958 | 170 | Coal |
| Peak Load | West Gardner Nos. 1-4 | 2003 | 308 | Natural Gas |
| | Osawatomie | 2003 | 76 | Natural Gas |
| | Hawthorn No. 9 | 2000 | 130 | Natural Gas |
| | Hawthorn No. 8 | 2000 | 76 | Natural Gas |
| | Hawthorn No. 7 | 2000 | 75 | Natural Gas |
| | Hawthorn No. 6 | 1997 | 136 | Natural Gas |
| | Northeast Black Start Unit | 1985 | 2 | Oil |
| | Northeast Nos. 17-18 | 1977 | 110 | Oil |
| | Northeast Nos. 13-14 | 1976 | 105 | Oil |
| | Northeast Nos. 15-16 | 1975 | 96 | Oil |
| | Northeast Nos. 11-12 | 1972 | 99 | Oil |
| | Spearville Wind Energy Facility(c) | 2006 | 15 | Wind |
| **Total KCP&L** | | | **4049** | |

[26] **RWIP** is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage

| Load | Unit | Year Completed | Estimated 2010 MW Capacity | Primary Fuel |
|---|---|---|---|---|
| Base Load | Iatan No. 1 | 1980 | 127(a) | Coal |
| | Jeffrey energy Center Nos. 1, 2 and 3 | 1978, 1980, 1983 | 173(a) | Coal |
| | Sibley Nos.1, 2 and 3 | 1960, 1962, 1969 | 466 | Coal |
| | Lake Road Nos. 2 and 4 | 1957, 1967 | 126 | Coal and Natural Gas |
| Peak Load | South Harper Nos. 1, 2 and 3 | 2005 | 314 | Natural Gas |
| | Crossroads Energy Center | 2002 | 297 | Natural Gas |
| | Ralph Green No. 3 | 1981 | 71 | Natural Gas |
| | Greenwood Nos. 1, 2, 3 and 4 | 1975-1979 | 252 | Natural Gas/Oil |
| | Lake Road No. 5 | 1974 | 63 | Natural Gas/Oil |
| | Lake Road Nos. 1 and 3 | 1951, 1962 | 22 | Natural Gas/Oil |
| | Lake Road Nos. 6 and 7 | 1989, 1990 | 43 | Oil |
| | Nevada | 1974 | 21 | Oil |
| **Total GMO** | | | **1975** | |
| **Total Great Plains Energy** | | | **6024** | |

(a) Share of a jointly owned unit.
(b) The Hawthorn Generating Station returned to commercial operation in 2001 with a new boiler, air quality control equipment and an uprated turbine following a 1999 explosion.
(c) The 100.5 MW Spearville Wind energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards

*Source: GREAT PLAINS ENERGY INC. 10-K. February 25, 2010*

*Staff Expert/Witness: Karen Lyons*

## 1. Iatan 2 Common Plant

Prior to the construction of Iatan 2, the original common plant at Iatan was identified solely as Iatan 1 plant. Iatan 1 originally had three partners who owned this investment: KCPL, The Empire District Electric Company (Empire) and St. Joseph Light and Power Company, currently L&P of GMO. KCPL had a 70% ownership share, L&P had an 18% ownership share and Empire had a 12% ownership share of the plant. All costs relating to this production unit were assigned on the basis of the ownership share, including the costs of the original common plant at Iatan.

After the completion of the Iatan 1 AQCS CEP project, because KCPL's ownership share of Iatan 2 differed from its ownership share of Iatan 2, KCPL's ownership share of the original common plant Iatan decreased. The Iatan Common Plant partners now consist of KCPL, Empire, L&P and two new partners, KEPCO and MJMEUC. As a result of the change in ownership, adjustments to the original Iatan Common plant were necessary to redistribute the ownership share of these facilities. Since Empire's and L&P's ownership shares of Iatan 2 remain the same as their respective shares in Iatan 1, the new partners' ownership shares in the Common Plant came out of KCPL's share of Iatan common plant costs. KCPL's new ownership share in the Iatan Common Plant is 61.45%. Because of this redistribution of KCPL's ownership share of the original common plant, the new owners had to pay KCPL for their shares of the original common plant costs. Adjustments had to be made to the plant costs for the common costs to reflect a reduction of KCPL's plant investment in Iatan common costs. These adjustments were made to the June 30, 2010 updated case for plant and depreciation reserve accounts to reduce the plant investment and the related depreciation reserve.

Adjustments P-33, P-39, P-40, P-42, P-43, P-204, P-207, P-210, P-250, P-258, P-260, P-261, P-262, P-265, R-33, R-39 R-33, R-39, R-40, R-42, R-43, R-204, R-207, R-210, R-250, R-258, R-260, R-261, R-262, R-265

*Staff Expert/Witness: Karen Lyons*

### <u>2. Iatan 2 Plant and Wind Turbines</u>

Iatan 2 met its in-service criteria on August 26, 2010. Staff included an estimate for Iatan 2 plant and reserve balances in this direct filing, because it has a reasonable basis to estimate them although Iatan 2 did not meet its in-service criteria prior to the end of the updated test year, June 30, 2010. Staff will include the October 31, 2010 Iatan 2 plant and reserve balances in Staff's true-up case. Staff has included in this direct filing an estimate for the plant and reserve balances associated with the Spearville 2 wind turbines, which are expected to meet their in-service criteria prior to the December 31, 2010 true-up cut off. Staff will update plant and reserve balances for both Iatan 2 and Spearville 2 in its true-up filing, reflecting October 31 and December 31, 2010 information, respectively.

*Staff Expert/Witness: Karen Lyons*

#### 3. Wolf Creek Disallowances

Missouri ratepayers share the cost of the Wolf Creek plant with Kansas ratepayers. The Company made an adjustment to remove the plant costs that do not apply to Missouri ratepayers. Staff made an adjustment to remove costs unrelated to the Company's Missouri operations. KCPL made the same adjustment in its case. Adjustments P-147.1 and P-160.1.

*Staff Expert/Witness: Karen Lyons*

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

The Cash Working Capital Schedule 8 identifies the amount of cash working capital that was determined by using lead-lag study. 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 that schedule in the section entitled "Subtract From Net Plant" to derive the amounts indicated as Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

KCPL sells its Account Receivables to Kansas City Receivables Corporation ("KCREC"). In June 2009, KCPL renegotiated its contract with KCREC which resulted in an increase in the purchase limit of receivables. As a result, the percentage of receivables sold increased and there was a decrease in the collection lag. This program increases immediate cash flow and provides access to funds through lines of credit. As a result of the immediate cash flow and the need to no longer attempt to collect on their account receivables, KCPL reduces the collection lag associated with cash working capital. Ratepayers benefit from the program since cash was generated by the sale of the receivables instead of from the ratepayers. More detailed information about KCPL's account receivable sales program can be found under the heading KCPL Receivable Bank Fees later in this report.

The Company performed a lead-lag study. The method used by the Company is very similar to that used by Staff in previous cases. Staff did not perform a complete CWC analysis in this case instead relying on the calculations made by KCPL and Staff in previous cases. However, upon review of the Company CWC schedule and work papers, Staff felt an analysis was needed with respect to Gross Receipt Taxes and Injuries and Damages.

KCPL pays Gross Receipt Taxes (commonly referred to as franchise taxes) for the right to do business in the municipalities in which it operates in. The tax is calculated based on a percentage of total revenues. This tax is listed on the ratepayer's statement as a separate line item. The Company can change the tax calculations as the rates charged by the municipalities tax rates change.

Staff reviewed the city ordinances for the Gross Receipt Tax ("GRT") to have a better understanding of how the tax was assessed and how it was collected. Staff found the tax was based on previous revenues on a semi-annual, quarterly or a monthly basis. Staff also reviewed the actual tax calculations made and submitted to the cities and townships for remittance of these taxes. For example, GRT accessed on a semi-annual basis with the payment due on January 31, 2009, would be calculated based on the revenues collected from July 1, 2008 through December 31, 2008. Staff calculated the time period from when KCPL collects from the customers to the time it remits the taxes to the taxing authorities. Based on this analysis, Staff determined that all municipalities served by KCPL require that the GRT be remitted to those taxing authorities after the GRT amounts are assessed, billed to KCPL's customers, and collected by the Company. Since the Company remits the GRT after it collects from its customers, these taxes are paid in arrears. The Company bills for the collection of the GRT along with the billing of electrical service and collects from the customers the same time as it collects for the provision of service. Customers are providing the cash for the GRT in advance which allows the Company to use these funds for a significant period of time prior to making payment to the municipalities. A lead-lag study was completed which resulted in an expense lag that was considerably higher than the Company calculated. The calculations for the gross receipts taxes are reflected in the CWC schedule (Schedule 8) as lines 22-24.

The City of Kansas City is by far the largest municipality where KCPL provides electrical service. Kansas City has two gross receipts taxes -- the 6% GRT-which is a quarterly tax- and the 4% GRT - which is a monthly tax. Both of these taxes are remitted to Kansas City after the Company collects the amounts due from its customers. Both taxes are calculated by the Company by using the preceding month or months and remits the taxes after collection. In the case of the quarterly gross receipts taxes, the three preceding months' revenues are the basis for the taxes. These taxes are paid to the city of Kansas City the month after the close of the quarter ended period. In the case of the monthly gross receipts taxes, the preceding one month's revenues are the basis for the taxes and they are remitted the following month. While KCPL correctly identifies these taxes as payments in arrears, or after-the-fact, the Company treats the larger 6% quarterly payments as a prepayment. KCPL incorrectly computed the GRT lag payments included in its CWC schedule. While the Company incorrectly included the GRT payment lag in the CWC calculation, it also incorrectly included the amount of GRT in its prepayments. Staff corrected these "errors" both in the CWC and excluded the GRT from rate base.

*Staff Expert/Witness: Karen Lyons*

### C. Prepayments

Prepayments are the costs a company incurs and pays in advance. KCPL buys property insurance to protect its assets, the costs of which are treated as a prepayment and included in rate base. Prepayments are treated as an asset and are reflected in the utility's rate base. Staff included amounts in its rate base for all prepayments that KCPL requires to provide electric utility service to its customers. Staff examined all of KCPL's prepayment account balances dating back to KCPL's previous rate case (ER-2009-0089) through June 30th, 2010, 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. These amounts were determined by multiple methodologies, including: calculating an average based on balances for the 13-months ending June 30th, 2010. Staff used this approach on accounts where there was no discernable upward or downward trend in the monthly balances. Staff also used the most recent account balance (June 30, 2010) on accounts where a noticeable upward or downward trend was present.

Staff did not include prepayments related to gross receipts taxes. While KCPL includes gross receipts taxes as a prepayment, Staff believes that these costs are actually paid in arrears and as a result, excluded these taxes from prepayments. The cash flow impact on KCPL for gross receipts taxes is reflected in Staff's Cash Working Capital calculation as shown on Schedule 8, Cash Working Capital (Accounting Schedule 2).

*Staff Expert/Witness: Bret G. Prenger*

### D. Customer Deposits

Customer deposits are the funds required to be provided by certain customers taking electrical service from the Company. These funds are deducted from the Company's rate base because these funds are cost-free funds received by the Company. The amount reflected for customer deposits on Accounting Schedule 2, Rate Base, is the most current customer deposit balance as of June 30, 2010. The balance reflected on the Rate Base Schedule is the Missouri jurisdictional total for customer deposits. The June 30, 2010, balance was used because the account balance exhibits a consistent trend. 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 2). Customers are paid interest for the use of the funds they provide to the Company on a cost free basis.

*Staff Expert/Witness: Bret G. Prenger*

### E. Customer Advances

Customer advances are funds typically provided by developers to the Company in order to ensure that the Company 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. Customer advances are included in the rate base as an offset, reducing the amount of overall investment that customers must supply as a return to the utility. (Accounting Schedule 2) The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents the last known balance of the account (balances ending June 30th, 2010) of KCPL's Missouri jurisdictional contributions.

*Staff Expert/Witness: Bret G. Prenger*

### F. Customer Deposits – Interest Expense

An amount of interest relating to customer deposits has been included as adjustment to the Income Statement - Schedule 9. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base -- Schedule 2 (see discussion in the Rate Base section of this report for customer deposits included in rate base). For this calculation, Staff used the customer deposit balance to be included in rate base, and then multiplied that number by the most current prime interest rate published in the Wall Street Journal (3.25) plus 1%, for a total of 4.25%. Adjustment E-135.2

*Staff Expert/Witness: Bret G. Prenger*

## G. Fuel Inventories

### 1. Coal Inventory

Based on the results obtained from the Staff's production cost model (fuel model), Staff included, as an addition to KCPL's rate base, an amount for coal inventory. Among other things, Staff uses its fuel model to determine an appropriate mix of generation unit and purchased power utilization to match the normalized native load of an electric utility. 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. For KCPL, 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 not usable as fuel due to contamination by 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 and the aggregated amount was multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown as coal inventory in Rate Base-Schedule 2.

*Staff Expert/Witness: V. William Harris*

## 2. Nuclear Inventory

To determine 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 inventory level 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 in the presentation of its direct case.

*Staff Expert/Witness: V. William Harris*

## 3. Oil and Fuel Additive Inventories

Staff used 13-month averages to determine the inventory levels for oil, limestone, ammonia and powder activated carbon inventories. A 13-month average inventory reflects the Company's actual experience for the entire 12-month test year period by including a beginning inventory and an ending inventory. For example, if the test year were a calendar year it 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) 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 Company'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 - Schedule 2. Staff's approach is consistent with the method used by KCPL in the presentation of its direct case.

*Staff Expert/Witness: V. William Harris*

### H. Material and Supplies

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 and maintenance activities by KCPL to maintain KCPL's production facilities and electric system. Staff reviewed the monthly balances for materials and supplies over the last several years because the account balances varied greatly depending on each individual account, Staff examined the accounts individually and determined an appropriate measure to most accurately predict the ongoing future of a particular account. Methodologies included: 13-month average and ending balances. (Accounting Schedule 2)

*Staff Expert/Witness: Bret G. Prenger*

### I. FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset

The Commission Staff and KCPL entered into a Stipulation and Agreement in Case No. ER-2009-0089 titled, "Nonunanimous Stipulation and Agreement Regarding Pension," (ER-2009-0089 Pension Stipulation). The ER-2009-0089 Pension Stipulation addressed the ratemaking treatment for annual pension cost under Financial Accounting Standard No. 87 (FAS 87), and pension settlement and curtailment accounting under Financial Accounting Standard No. 88 (FAS 88).

The ER-2009-0089 Pension Stipulation reaffirms the agreement regarding these matters reached in the KCPL Regulatory Plan Stipulation and Agreement, approved by the Commission in Case No. EO-2005-0329 (the Regulatory Plan), and clarifies the accounting for pension cost allocated to KCPL's joint partners in the Iatan and LaCygne generating stations. The ER-2009-0089 Pension Stipulation also addresses the ratemaking treatment for a curtailment or settlement recognized under FAS 88, and is consistent with the Stipulation and Agreement reached between Staff and KCPL in the KCPL 2006 rate case, Case No. ER-2006-0314 (ER-2006-0314 Pension Stipulation).

There are two amounts in rate base resulting from the Stipulation and Agreements in Case Nos. EO-2005-0329, ER-2006-0314, ER-2007-0291 and ER-2009-0089:

1) A Prepaid Pension Asset – The prepaid pension asset represents the unrecovered balance of negative pension cost flowed back to ratepayers in prior years. When this regulatory asset has been fully recovered, KCPL will be required to fund its annual FAS 87 pension cost reflected in its financial statements under the terms of the Stipulation and Agreements in Case Nos. EO-2005-0329, ER-2006-0314, ER-2007-0291 and ER-2009-0089.

2) An 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. KCPL's rate base includes a regulatory asset as of June 30, 2010.

Both of these rate base amounts will be trued-up as of December 31, 2010, during the true-up audit scheduled for this case, File No. ER-2010-0355. (Rate Base Schedule 2)

*Staff Expert/Witness: Paul R. Harrison*

## J. Iatan Unit 2 Construction Accounting

"Construction accounting" is defined in the Stipulation and Agreement authorizing Kansas City Power & Light Company's Experimental Regulatory Plan as finally amended and approved by the Commission in Case No. EO-2005-0329 at page 43, Section III.3.d.vii.:

> (vii) Construction Accounting. The Signatory Parties agree that KCPL should be allowed to treat the Iatan 2 project under "Construction Accounting" to the effective date of new rates in the 2009 Rate Case. Construction Accounting will be the same treatment for expenditures and credits consistent with the treatment for Iatan Unit 2 prior to Iatan Unit 2's commercial in service operation date. Construction Accounting will include treatment for test power and its valuation consistent with the treatment of such power prior to Iatan Unit 2's commercial in service operation date with the exception that such power valuation will include off-system sales. The AFUDC rate that will be used during this period will be consistent with the AFUDC rate calculation in Paragraph III.B.1.g. The amortization of the amounts deferred under this Construction Accounting method will be determined by the Commission in the 2009 Rate Case. The non-KCPL Signatory Parties reserve the right to challenge amounts deferred under this Paragraph in the event that they contend that the Iatan Unit 2 commercial in service operation date was delayed due to imprudence relating to its construction.

The "2009 Rate Case" in the Stipulation and Agreement in Case No. EO-2005-0329 refers to the fourth case in KCPL's Regulatory Plan. The current rate case, File No. ER-2010-0355 is that fourth case.

The update cutoff of this report is June 30, 2010. As of this date, Iatan Unit 2 has not met the in-service criteria established in KCPL's Regulatory Plan. At the time of the true-up in this case, Staff will review and evaluate the calculations made for Construction Accounting, including the test power calculations for Iatan Unit 2.

*Staff Expert/Witness: Keith A. Majors*

# VI. Income Statement – Revenues

## A. Rate Revenues

### 1. Introduction

This section describes how Staff determined the level of KCPL Operating Revenues. Since the largest component of operating revenues result from rates charged to KCPL's Missouri retail customers, a comparison of operating revenues with cost of service is fundamentally a test of adequacy of the currently effective Missouri jurisdictional retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates KCPL charges its Missouri retail customers for electricity is required.

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 made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenue) prospectively. Operating Revenues are composed of Margin from 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 charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. In Missouri, different rates apply to different times of the year (summer vs. winter); different types of charges (demand, energy); and to customers in different rate classes.

*Staff Expert/Witness: Curt Wells*

### 2. The Development of Rate Revenue in this Case

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

The purpose of Staff's adjustments to test year (January 1, 2009- December 31, 2009) Missouri usage and rate revenues is to determine the level of revenue that the Company would have collected on an annual, normal-weather basis, based on information "known and measurable" at the end of the update period (June 30, 2010). The two major categories of revenue adjustments are known as "normalization" and "annualization". Normalization deals with test year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect, e.g., test year weather. Annualizations are adjustments that re-state test year results as if conditions known at the end of the update period had existed throughout the entire test year.

This report briefly describes the following regulatory adjustments Staff made to test year billed rate revenues:

a. weather normalization
b. annualization for the rate change on September 1, 2009
c. 365-day adjustment
d. customer growth
e. large customer annualization and rate switching
f. special contracts and other customer discounts

Not all adjustments affect both usage and rate revenue. Not all rate classes are subject to all seven adjustments.

*Staff Expert/Witness: Curt Wells*

### 3. Regulatory Adjustments to Test Year Sales and Rate Revenue

#### a. Weather Normalization

##### i. Weather Normals Used in Weather Normalization

The actual weather experienced during the test year is unique and unlikely to be repeated exactly in each of the years when the new rates from this case will be in effect. Thus, for purposes of determining appropriate rate levels, actual test year electricity usage is adjusted to the level that would be expected under "normal" weather.

The time period used in determining the normal values of weather variables is the 30-year period (January 1, 1971- December 31, 2000) as used by NOAA27. NOAA, states that "climate normal is defined, by convention, as the arithmetic mean of a Climatological element computed over three consecutive decades." However, NOAA's daily normals are derived by statistically fitting smooth curves through monthly values, and as a result they do not contain daily variation in temperature for weather-normalizing electricity use. The weather normalization of electric usage requires daily temperature normals, because electricity usage varies differently at extreme daily temperatures than it does at mild daily temperatures. Consequently, Staff adjusted its daily data so that the monthly average of the daily data equals the NOAA monthly average.

Staff used daily temperatures from the Kansas City International Airport (MCI) to develop "normal" temperatures with which to compare test year temperatures. The data required to weather normalize usage are the actual and normal two-day weighted mean daily temperatures. To calculate the two-day weighted mean temperature, the current day's mean temperature is averaged with the prior day's mean temperature applying a 2/3 weight on the

[27] National Oceanic and Atmospheric Administration

current day and 1/3 weight on the prior day. This is done in order to carry forward the previous day's residual effect on the current day's usage.

Every year contains some extreme weather. Therefore, to weather normalize usage, normal extreme values are estimated using a ranking method. The ranking method estimates daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating normal extremes. The daily temperature normals are estimated by averaging the ranked temperatures in each year of the 30-year normals period, irrespective of the calendar date. This results in the normal extreme being the average of the most extreme temperatures in each year. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

Actual temperatures do not smoothly increase or decrease during the year.[28] This impacts the daily loads which, in turn, impacts the dispatch of generating units. To imitate daily fluctuations, these ranked normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test year and the month of the year that the rank normally occurs on.

This information is made available to Staff witnesses Walt Cecil to use normal weather in both the normalization of class usage and hourly net system loads. KCPL used the same method to calculate daily normal weather values. This information was used in the review of KCPL's weather normalization of net system input and billing usage.

*Staff Expert/Witness: Seoung Joun Won*

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[28] For example, in July a Monday and Tuesday may be hot days but it cools down on Wednesday. However, it is still likely that on the weekend it will be hot again.

### ii. Weather Normalization of kWh

Staff estimates what energy usage would have been given a year of normal[29] temperatures to calculate the revenue KCPL would have billed and what the load requirements of its customers would have been. Normalization is conducted on the Residential, Small, Medium and Large General Service classes because a significant amount of the electrical energy consumed by customers in these classes is used for climate control, which responds to the weather and daily changes in the weather.[30]

The winter and summer seasons during the 2009 test year included both cooler-than-normal and warmer-than-normal months. Staff reviewed KCPL's input data, weather normalization methodology and the resulting weather adjustments and agrees with and, therefore, adopts KCPL's weather normalization adjustments for the Residential, Small, Medium and Large General Service classes.

Staff does not adopt KCPL's Large Power Class' weather normalization. Relative to the other classes, the Large Power Class consists of a small number of customers whose operations greatly differ from one another in the amount of electricity used and how it is used across the hours of the day. As a brief and not all-inclusive example, this class includes hospitals, a large phone company, an amusement park, an automobile manufacturer a steel mill and a cement manufacturer. Further, there are businesses in the class, such as an amusement park, whose activities are more sensitive to the economic cycle and/or time-of-year than to the weather. Because the usage of these customers was highest in July and August – not because it was hot but because it was July and August - the presence of such businesses in the class increases the

[29] For a full explanation of normal weather and how it is calculated, refer to Staff witness Manisha Lakhanpal's discussion in section 4. a., Weather Normalization.

[30] Classes that experience load fluctuations in response to fluctuations in the weather are referred to as "weather sensitive."

class' overall electric usage making the class appear to be more weather sensitive than it is. The treatment of this class' data is fully discussed in *Section D, Large Customer Annualization and Rate Switching*.

*Staff Expert/Witness: Walt Cecil*

**iii. The Effect of the Weather Normalization of kWh Usage on Rate Revenue**

To calculate weather-normalized revenue, current rates were applied to weather normalized usage. Staff's weather normalization adjustment is equal to the difference between weather-normalized revenues and the test year revenues.

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 kWh usage. Staff reviewed and accepted KCPL's adjusted usage for rate switcher31 prior to weather normalization.

*Staff Expert/Witness: Manisha Lakhanpal*

**b. Annualization for Rate Change**

Staff annualized current rates which became effective September 1, 2009, to reflect a full year's revenues at those rates. The test year of calendar year 2009 revenues reflect rates prior to September 1, 2009 and the current rates after September 1, 2009 which were established in Case No. ER-2009-0089. Thus, for all rate classes, test year revenues are understated by the difference between the amount that was actually billed to customers and the revenue that would have been realized by the Company if the current rates had been in effect throughout the entire test year.

[31] Rate Switchers are primarily industrial and commercial customer accounts that switch between different rate groups that better suits their consumption pattern.

Staff computed annualized revenues based on September 1, 2009 rates for each rate class by applying these new rates to test year annualized, normalized billing units for each class.

*Staff Expert/Witness: Manisha Lakhanpal*

**c. 365-Days Adjustment For Weather Sensitive Classes**

Staff calculated a normalization adjustment to KCPL's usage to reflect a calendar year's (365 days) worth of usage. KCPL's customers' usage is measured and rate revenue are collected over a period known as a revenue month, which is the interval that KCPL reads customers' meters and issues bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months, but revenue months take their names from the name of the calendar month in which the customer's bill is rendered. For example, the usage of a customer was read on June 8 and then again on July 8. The bill was sent to the customer on July 15. The revenue month for this bill is July even though the majority of the usage measured for this bill was used in June.

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than or less than the number of days for the same-named calendar month. For the example given above, the usage is for 30 days (June 8 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. Therefore since the costs and expenses are for a calendar year, Staff calculates a normalization adjustment to bring the revenue year into a 365 day interval. This adjustment is referred to as a *days adjustment*.[32]

Staff performed a days adjustment for both Missouri and Kansas jurisdictional usage. Staff calculated the difference between the weather normalized calendar month sales over the test-year, and the weather normalized revenue month usage over the test-year. The days adjustments to both Missouri and Kansas usage were provided to Staff witness Alan J. Bax to be used in the calculation of the energy jurisdictional allocator. Staff witness Curt Wells used the Missouri jurisdictional usage to adjust the revenues of the weather normalized class revenues months to the 2009 calendar year.

*Staff Expert/Witness: Walt Cecil*

**d. 365-Days Revenue Adjustment For Weather Sensitive Classes**

A revenue adjustment was calculated for Missouri weather sensitive classes by allocating the days adjustment proportionately to the appropriate revenue month weather-normalized kWh usage for each class and then applying current rates. The differences between the days adjusted revenue and the actual revenue is the "days" adjustment to revenues.

*Staff Expert/Witness: Manisha Lakhanpal*

**e. 365-Days Adjustment for Large Power**

For the Large Power Service (LPS) rate group an adjustment is made to each customer's usage each month, depending on the number of days in a bill cycle, by either adding the appropriate number of days of daily average usage when there were less than 365 days of usage in twelve revenue months, or subtracting the appropriate number of days of usage when there were more than 365 days of usage in twelve revenue months. Appropriate seasonal rates are applied to this adjusted usage to obtain revenue. The differences between the days adjusted

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

usage and the actual usage is the "days" adjustment. The 365-days adjustment for the LPS class is then used to calculate a days adjustment to revenue.

*Staff Expert/Witness: Seoung Joun Won*

### B. Customer Growth

Customer growth adjustments were made to 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, 2010) had existed throughout the entire test year. Customer growth was calculated for the Residential, Small General Service, Medium General Service, and Large General Service rate classes using customer levels as of June 30, 2010. Cognizant of the Commission's Report and Order in KCPL's 2007 rate case, Case No.ER-2007-0291, Staff ensured that KCPL has restricted the availability of its general service all-electric and separately-metered space heating discounted rates to those qualifying customers being served under such rates as of January 1, 2008.

*Staff Expert/Witness: Amanda C McMellen*

### C. Additional Revenues from Customer Growth During the Update Period

For this direct testimony filing, Staff updated all elements of revenue, expense, and rate base over the 2009 test year level for any known and measurable changes through June 30, 2010. A review of the pertinent facts at June 30, 2010, indicates that KCPL has experienced an increase in its revenues since the end of the test year, due to overall growth in the number of its utility customers. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff has employed the following method of computing the annualized level of increased revenue from customer growth at June 30, 2010. For each customer rate group, the customer level during each month of the test year is compared to the level at June 30, 2010, and the monthly change in 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. The total growth in revenues is arrived at by performing this comparison and multiplication for each month of the test year, and then summing the results. In short, this 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, 2010.

The only retail customer rate group for which this approach is not taken is the Large Power group. With respect to Large Power customers, energy consumption and revenue patterns to 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'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 customers in order to provide the annualized level at June 30, 2010. The adjustment for retail customer growth other than Large Power is Rev-3.8.

*Staff Expert/Witness: Amanda C McMellen*

### D. Customer Growth in Usage

Staff adjusted test year kWh sales and rate revenue for the Missouri jurisdiction for customer growth to reflect the additional kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of the update period (June 30, 2010) had existed throughout the entire test year. Customer growth in revenues was calculated for Missouri jurisdiction's Residential, Small General Service, Medium General Service, and Large General Service rate classes only.

Customer growth adjustments were also applied to kWh usage in the Kansas jurisdiction to be used along with the Missouri adjusted usage in the calculation of the jurisdictional allocation factor.

*Staff Expert/Witness: Manisha Lakhanpal*

### E. Large Customer Annualization and Rate Switching

Because each Large Power Service (LPS) customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor, class sales and revenues were annualized on an individual customer account basis. LPS revenues were annualized for major growth or decline in kWh sales and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers active at the end of the update period.

Staff analyzed LPS data during the test year and through the update period. A data check for billing corrections was done prior to making any adjustments. Each customer’s individual monthly demand and energy use, measured over multiple years prior to the test year and the twelve months of the test year, were examined graphically to determine whether an adjustment was needed.

At the beginning of the test year there were ninety-seven LPS customers and at the end of the update period, there were eighty-six. Fifteen customers switched out of the LPS and into the Large General Service (LGS) rate group, and one LPS customer quit taking service from KCPL. Therefore, the total LPS load was reduced by the loads of the above mentioned customers. One customer switched into the LPS class from the LGS class. This adjustment was made by moving their customers test year usage data for the affected months from the data for the LGS class to the data for the LPS class.

Three new customers joined the LPS class during test year. For new customer accounts with less than twelve months of billing information, missing data was estimated by substituting data from the updated period. In addition review of the current customer loads showed the loads of some customers needed to be adjusted to match the customer's loads in the update period. The annualization adjustment for new LPS customers and load changes for existing customer accounts due to abnormal usage in the test year is conducted.

In the Kansas jurisdiction, there are three LPS customers in the rate group at the end of the test year. This information is used along with the Missouri adjusted usage in the calculation of the jurisdictional allocation factor.

*Staff Expert/Witness: Seoung Joun Won*

## 1. Special Contracts and Other Customer Discounts

**Special Contracts:** There are Missouri LPS customers who pay a discounted rate for electricity because of special contracts that each has with KCPL. Pursuant to the KCPL Regulatory Plan, Staff has "imputed" the revenue from these contracts (i.e., calculated revenue as if the discounts did not exist) to ensure that these discounts will be "paid" by shareholders and not by any of KCPL's other rate payers.

**PLCC/MPower:** Peak load curtailment credits are paid to customers that agree to curtail a portion of their peak load when requested by KCPL. These discounts are assumed to be a benefit to all ratepayers and thus are not excluded from the determination of KCPL's revenues

**EDR:** The Economic Development Rider (EDR) provides for discounts to be "paid" to customers (in the form of credits on their electricity bill) who locate or expand operations in KCPL's service territory. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. Depending upon the contract year the customer is in, the discount can be as high as 30% (year 1) to as low as 10% (year 5). Staff assumed that the annualization for the rate change would be reflected in both the level of the bill before the credit and in the amount of the credit itself (i.e., a 10% rate change would increase both the pre-credit bill and the EDR credit by 10%). These discounts are included in the determination of KCPL's revenues because fostering economic development is assumed to be a benefit to all ratepayers.

Normalized Rate Revenue summary for Missouri jurisdiction can be found as an attachment to the Staff Accounting Schedule.

*Staff Experts/Witnesses: Manisha Lakhanpal and Seoung Joun Won*

## F. Bulk Power Sales

### 1. Deferred Sales from $SO_2$ Emissions Allowances

Since KCPL receives more $SO_2$ emission allowances ("$SO_2$ 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 ("FERC USOA"), proceeds from the sales of surplus $SO_2$ emissions allowances are recorded in FERC Account 254, the FERC 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 has included in its direct case the balance of Account 254 on June 30, 2010, as an offset to rate base. This approach is consistent with the treatment in the last three KCPL rate cases, Case Nos. ER-2006-0314, ER-2007-0291 and ER-2009-0089. The rationale for treating these $SO_2$ emissions allowances in this manner is to acknowledge 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: V. William Harris*

### 2. FERC Account 447-Sales for Resale

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

#### a. Firm Off-System Sales

KCPL contracts to sell firm off-system power to the following customers:

1. City of Independence, Missouri; and
2. City of Springfield, Missouri

Under their respective contracts, these customers pay both a demand charge for the megawatt capacity commitment from KCPL and an energy charge for the cost of delivered energy. KCPL also sells firm off-system energy to City of Chanute, Kansas, Kansas Municipal Energy Agency ("KMEA") and Missouri Joint Municipal Electric Utility Commission ("MJMEUC").

Staff has reviewed KCPL's firm off-system sales levels from 2006 to the present and adjusted test year levels to reflect the levels for the 12-month update period ended June 30, 2010.

*Staff Expert/Witness: V. William Harris*

#### b. Non-Firm Off-System Sales

Non-firm off-system sales are sales of electricity made at times when a utility has met all of its obligations to serve its native load customers (rate tariff customers) and firm sale customers, and has excess electricity it can sell to others. Off-system sales (OSS) result in profits (net margin) to the selling utility, in this case KCPL. OSS are typically made at market-based rates. The aggregate profits of these OSS are used to lower the electric utility's revenue requirement.

The Commission, in Case Nos. ER-2006-0314, ER-2007-0291 and ER-2009-0089, adopted and relied on KCPL consultant Michael M. Schnitzer's projected level of net margin at the 25th percentile for the net margin of non-firm OSS to include in KPCL's cost of service. A projected level of net margin at the 25th percentile results in a 75% probability of KCPL attaining that level of OSS margins or higher. Mr. Schnitzer has updated his analysis for this case and filed his findings on June 4, 2010, as part of the Company's original direct filing. Staff has included Mr. Schnitzer's original projected level of net margin of ** ___ ** million, total company, at the 25th percentile in determining KCPL's cost of service.

| The off-system sales levels since 2006 have been as follows: **Year** | **Off-System Sales Total Company** | **Net Margin** |
|---|---|---|
| 2006 | $ 158,982,025 | $ 87,282,307 |
| 2007 | $ 158,739,779 | $ 64,087,726 |
| 2008 | $ 102,956,374 | $ 56,056,149 |
| 2009 | $ 91,878,117 | $ 32,424,214 |

At page 36 of its *Report and Order and Order Regarding Motions for Rehearing* in Case No. ER-2006-0314, the Commission included a requirement to track the OSS net margin included in cost of service with KCPL's actual OSS net margin and flow back the excess to ratepayers as a reduction to cost of service. In KCPL's next two rate cases, ER-2007-0291 and ER-2009-0089, the Commission ordered a continuation of the net margin tracking mechanism the Commission originally ordered in Case No. ER-2006-0314.



**NP**

Please refer to the testimony of Staff witness Charles R. Hyneman for a complete discussion regarding the Staff's proposed treatment of the net margin tracking mechanism.

*Staff Expert/Witness: V. William Harris*

**c. Adjustments to Non-Firm Off-System Sales**

KCPL is proposing three adjustments that reduce Mr. Schnitzer's level of net margin from Non-Firm OSS at the 25$^{th}$ percentile. KCPL witness Burton L. Crawford sponsors these adjustments:

(1) Purchases for Resale – wholesale sales that are supplied by purchased power as compared to wholesale sales supplied by KCPL owned generation.

(2) Southwest Power Pool ("SPP") line loss charges (net of line loss revenue).

(3) SPP's Revenue Neutrality Uplift (RNU) charges – imbalances between revenues and disbursements that are distributed among SPP market participants as either a charge or a credit. This is the first rate case that KCPL has proposed this type of adjustment.

Staff accepts KCPL's proposed adjustments for purchases for resale and RNU charges. However, Staff only agrees in part with KCPL's proposed adjustment for SPP "line loss charges." These charges relate to an SPP member's sale of wholesale energy to an entity outside the SPP market. The seller pays the charges to compensate other SPP members for transmission system energy loss. Staff agrees with KCPL that an adjustment should be made to reflect the revenues associated with SPP compensating payments from other SPP members. However, Staff has received assurances from KCPL that none of the data given Mr. Schnitzer contains off-system sales made outside the SPP system. Mr. Schnitzer's model should not be adjusted to reflect charges related to sales that are not in Mr. Schnitzer's database. Therefore, Staff opposes this portion of the SPP "line loss charges" adjustment.

*Staff Expert/Witness: V. William Harris*

**d. 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, revenues, fuel and purchased-power 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: V. William Harris*

## G. Miscellaneous Revenues

### 1. Late Payment Revenue (Forfeited Discount)

KCPL charges a late payment fee[33] 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 from July 1, 2009, through June 30, 2010. This ratio was multiplied by the Staff annualized revenue, plus test year gross receipt taxes (GRT). Since GRT is assessed on revenue generated from late payment fees, the calculation of the Missouri adjustment is based on Total Revenue, which includes GRT. This is reflected in the Staff Accounting Schedule as adjustment Rev-18.2.

*Staff Expert/Witness: Amanda C McMellen*

[33] Late payment fees are also referred to as a "forfeited discount."

## 2. Miscellaneous Services

KCPL is seeking a change to its tariff in this case to include In-Field Service Fees.[34] An in-field service fee is a fee that is charged to a customer that makes a payment to a KCPL employee when that employee arrives to disconnect that customer for non-payment. Staff will address the tariff issues related to these fees in the Staff Class Cost of Service Rate Design testimony that is due on November 24, 2010. Staff has accepted KCPL's revenue adjustment for in-field service fees, and agrees with the annualized level KCPL calculated. This is reflected in the Staff Accounting Schedule as adjustment Rev-21.1.

*Staff Expert/Witness: Amanda C McMellen*

## 3. Other Revenue Accounts

Staff reviewed the amounts KCPL included in its cost of service calculation for Other Revenues, which include rent from electric property, replacement of damaged meters, disconnect service charge, temporary installation profit, and other transmission service revenues, among others. The analysis of these amounts included a review of the revenues over the last eight and a half years through June 30, 2010. In Staff's opinion, the test year Other Revenues amounts appeared to be representative and reasonable 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, 2010.

*Staff Expert/Witness: Amanda C McMellen*

[34] In-field service fees are also referred to as "collection fees."

## VII. Income Statement - Expenses

### A. Fuel and Purchased Power Expense

#### 1. 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." The non-variable purchased power costs not included in Staff's fuel model are commonly referred to as "capacity charges" and are annualized separately from purchased power energy costs.

*Staff Expert/Witness: V. William Harris*

#### 2. Fixed Adders

As described above, fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in Staff's fuel model. The costs of fuel adders are determined separately and are added to the level of fuel expense calculated by the model to determine overall fuel expense. Costs added to coal expense include unit train lease payments and unit train 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.

Staff used the actual prices for June 2010 in determining its annualized level for all fuel adders in this direct filing.

*Staff Expert/Witness: V. William Harris*

### 3. Purchased Power - Energy

Staff Adjustment E-74.2 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, Shawn E. Lange is responsible for determining the appropriate amount of power purchased and the proper price for this power.

*Staff Expert/Witness: V. William Harris*

### 4. Purchased Power – Capacity Charges

Capacity charges, commonly referred to as "demand charges," represent fixed amounts that KCPL paid to the entity that reserves megawatt electric capacity for KCPL. KCPL contracts this power with various entities and pays a fixed component for the reserve capacity and an energy component for 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 reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

Staff Adjustment E-74.1 annualizes purchased power demand charges based on existing capacity contracts in effect. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff reviewed each of these contracts and determined the appropriate costs per megawatt hour and the amount of megawatts purchased. Staff included the costs reflected in KCPL's capacity agreements that were in effect on June 30, 2010.

*Staff Expert/Witness: V. William Harris*

### <u>5. Variable Costs</u>

Staff has performed three model scenarios to reflect the impact of Iatan 2 on KCPL's variable fuel costs on a going forward basis. The first scenario, as described in Staff's Executive Summary, uses test year inputs ending December 2009, as updated through June 30th, 2010. The use of an update date of June 30, 2010 results in the Iatan Unit 2 and the Spearville 2 wind farm project being excluded from this scenario. Under this scenario Staff estimates the variable fuel and purchased power expense for KCPL to be ** ___________ **.

The second scenario, as described in Staff's Executive Summary, uses test year ending December 2009, as updated through December 31, 2010. This scenario captures Iatan unit 2, the Spearville 2 wind farm, and updated fuel prices supplied by the Staff of the Commission's Auditing Department. Under this scenario Staff estimates the variable fuel and purchased power expense for KCPL to be ** ___________ **.

The third scenario uses Scenario 1 test year inputs ending December 2009, as updated through June 30, 2010. The difference is that Iatan 2 and the Spearville 2 wind farm are included as generation resources in this scenario. This scenario results in variable fuel and purchased power costs of ** ___________ ** which is ** __________ ** below the scenario 1 fuel costs. Since the fuel costs in scenario 2 were less than that of scenario 1, the increase in fuel and purchased power expense from scenario 1 to scenario 2 is a result of the updated fuel prices supplied by the Auditing Staff.



**NP**

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

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

Model inputs calculated by Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input ("NSI"), and unit planned and forced outages. Staff relied on KCPL responses to data requests for factors relating to each generating unit. These factors include: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense as well as information from KCPL's firm wholesale loads. Firm purchased power contract information, such as hourly energy available and prices, are also inputs to the model.

*Staff Expert/Witness: Shawn E. Lange*

**a. Fuel Prices**

Staff computed fuel expense using prices and quantities incurred by KCPL through June 30, 2010. This included using fuel prices for nuclear, coal, natural gas, and oil, including transportation charges in fuel accounts 501 (coal), 518 (nuclear), 547 (natural gas).

*Staff Expert/Witness: V. William Harris*

**b. Coal Prices**

Staff determined its coal price by generation facility based on a review and analysis of KCPL's coal purchase (supply) and coal transportation (freight) contracts. Staff's proposed coal prices reflect KCPL's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect on June 30, 2010.

*Staff Expert/Witness: V. William Harris*

**c. Natural Gas Prices**

As an input to its production cost model, Staff used twelve monthly natural gas prices calculated using 2-year weighted averages of KCPL's actual commodity cost of natural gas through the known and measurable period updated through June 2010 (i.e. January 2009/2010 through June 2009/2010 and July 2008/2009 through December 2008/2009). KCPL's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

*Staff Expert/Witness: V. William Harris*

**d. Nuclear Fuel Prices**

KCPL owns 47% of Wolf Creek Nuclear Operating Corporation ("Wolf Creek"), the operating company for the Wolf Creek nuclear plant. KCPL's 47% ownership interest in Wolf Creek entitles it to 548 megawatts of the plant's capacity. In making its nuclear fuel price proposal, Staff relied upon KCPL's monthly Report 25, Fuel Report, for 2009 through June 2010. Staff noted that monthly nuclear fuel costs over the last few years varied within a small range. Staff's proposed nuclear fuel price is based on an average of the monthly fuel costs incurred over the 18-month period from January 2009 through June 2010.

*Staff Expert/Witness: V. William Harris*

**e. Oil Prices**

Staff used the actual cost KCPL paid for its most recent fuel oil purchases. KCPL burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Oil is only a primary fuel source at KCPL's Northeast units, which see very limited run time. As a result, KCPL purchases fuel oil infrequently. 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. Staff believes KCPL's most recent fuel oil purchase prices are the best available fuel oil cost to input into the fuel model for determining KCPL's variable fuel and purchased power expense on a going forward basis.

*Staff Expert/Witness: V. William Harris*

## 6. Spot Market Prices

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

Staff used a procedure developed by the Commission's Energy Department – Engineering Section in 1996 that is described in "A Methodology to Calculate Representative

Prices for Purchased Energy in the Spot Market" (March 18, 1996). The method uses a statistical calculation based on the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.

Actual hourly non-contract transactions prices for KCPL and GMO during the update period are obtained from the data that the Companies supplied to comply with 4 CSR 240-3.190 and are used as price inputs in the calculation. Staff used the combined data from both KCPL and GMO to reflect the market that exists in this region. The calculation yields a spot energy price for each hour of the year.

*Staff Expert/Witness: Erin L. Maloney*

### 7. Capacity Contract Prices and Energy

Capacity contracts are contracts between two utilities for a specific amount of capacity and a maximum amount of hourly energy. Energy for two of the capacity contracts held by KCPL is purchased at market prices. They were not included in the production cost model because the model would not differentiate between the contracts and purchasing on the spot market. Two other contracts are for energy from units which can be dispatched by KCPL. Those two units are included in the production cost model as dispatchable units.

*Staff Expert/Witness: Shawn E. Lange*

### 8. Hourly Net System Loads

Hourly net system load is the hourly electric supply necessary to meet the energy demands of both the company's customers and the company's own needs. The hourly loads used in the analysis of the test year ending December 2009, were provided in KCPL's direct testimony work papers. Hourly load data submitted monthly by KCPL in compliance with the Commission's rule 4 CSR 240-3.190 was used to cross check the company's hourly load data.

Due to the high usage of electrical energy for air conditioning and electric space heating in KCPL's electric service territory, the magnitude and shape of KCPL's net system input is directly related to daily temperatures. To reflect normal weather, daily peak and average net system loads were adjusted independently, but using the same methodology. Independent adjustments are necessary because average loads and peak loads respond differently to weather.

Daily average load is calculated as the daily energy divided by twenty-four hours and the daily peak is the maximum hourly load for the day. Separate regression models estimate both a base component, which is allowed to fluctuate across time, and a weather sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. The 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 peak loads for each day. Actual and normal daily temperatures developed using the average and ranking methodology described in this report was used in this analysis.

A unitized load curve was calculated for each day as a function of the actual peak and average loads for that day. The corresponding weather-normalized daily peak and average loads, the unitized load curves and the actual hourly loads were then used to calculate weather-normalized hourly loads.

Staff uses the process described in Weather Normalization of Electric Loads, Part A: Hourly Net System Loads [35].

Once Staff's weather normalized, annualized test year kWh usage for both Missouri and non-Missouri customers is determined, weather normalized wholesale usage was added and the

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[35] 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.

resulting sum is increased by the loss factor to obtain the total amount of generation (net system input) necessary to serve the metered kWh consumed by customers on an hourly basis for the test year - 8760 values. Finally, Firm Capacity Contract Customers' hourly loads were added to the factored net-system load.

Once completed, the test-year hourly normalized system loads were provided to Staff witness Shawn E. Lange and used in developing the test year fuel and purchased-power expense. The annual requirement of the net system hours was used by Staff witness Alan J. Bax in developing Staff's jurisdictional energy allocator.

*Staff Expert/Witness: Walt Cecil*

### a. Normal Weather

Please refer to the revenue section of this report for a description of how Staff calculates normal weather.

#### i. Losses

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

Staff calculates system energy losses as a percentage of Net System Input (NSI), where NSI is equal to the kWh sum of KCPL's retail and wholesale sales, plus the electrical energy KCPL used in the operation of its facilities (Company Use), plus system energy losses. In other words, NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses. This equation may be rearranged to solve for system energy losses as follows: System energy losses = NSI – (Retail Sales + Wholesale Sales + Company Use).

NSI is also equal to the sum of net generation, plus the net of off-system purchases and sales (net interchange). Net generation and net interchange are known quantities as are Retail Sales, Wholesale Sales and Company Use. Therefore, by inputting these components into the above equation, one can solve for system energy losses. Staff then divides the resulting system energy losses by NSI and multiplies by 100 ((system energy losses/NSI) X 100%) to obtain the system energy losses as a percentage of NSI. This result is referred to as the system energy loss factor, also called the line loss factor.

Staff has calculated a system energy loss factor for the twelve months ending December 2009 of 5.63% of its NSI. This is the line loss percentage provided to Staff witness, Walt Cecil used in developing the system loads that are inputted into Staff's fuel model.

*Staff Expert/Witness: Alan J. Bax*

#### **9. Planned and Forced Outages**

Planned and forced outages affect what units are available for dispatch to meet load. Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the KCPL generating unit outages were normalized by averaging the seven years of actual values taken from data supplied by KCPL.

*Staff Expert/Witness: Shawn E. Lange*

### B. Payroll, Payroll Related Benefits including 401K Benefits Costs and

#### **1. Payroll Costs**

Staff has examined the payroll costs of KCPL. All employees of Great Plains Energy are considered employees of KCPL. These KCPL and GPE employees perform all services for Great Plains Energy, KCPL and GMO (MPS and L&P). An allocation of costs is necessary to assign a proper amount of payroll costs to each of the Great Plains Energy entities. Staff has reviewed the allocation of actual assigned payroll costs for each of these entities since the acquisition of the former Aquila Missouri electric operations of MPS and L&P and allocated the annualized payroll based on this allocation.

The transfer of the former Aquila employees was made at the close of the acquisition transaction on July 14, 2008. The former Aquila entities now are providing utility services under the name KCP&L Greater Missouri Operations Company: GMO MPS, GMO L&P and GMO L&P Steam. Because all former Aquila employees providing service to the GMO MPS, GMO L&P and GMO L&P steam operations became part of the KCPL employee base, KCPL now has to allocate costs directly to each KCPL service territory and the two GMO operating entities, MPS and L&P. Additionally, L&P operations supplies utility services to electric and steam customers and L&P labor costs must be allocated between the electric and steam operations.

Based on the other allocation amounts to the GPE entities, Staff concluded that the actual charged amounts were the best allocation of payroll between KCPL, MPS and L&P. Staff utilized actual charged amounts to the three operating entities, net of joint partners, Wolf Creek, and Jeffrey Energy Center charged payroll. The joint partners' costs are amounts charged to KCPL's other partners of the generating assets owned and operated by the Company, with the exception of Wolf Creek, a separate operating company 47% of which is owned by KCPL.

Staff annualized payroll costs in this case using actual employee levels as of the update period of June 30, 2010. Wages and salaries as of June 30, 2010, were applied to each individual employee to compute the total GPE and KCPL payroll costs on an annual basis. Annualized payroll included differential and premium pay paid to KCPL employees based on union contracts.

As of June 30, 2010, KCPL's holding company, GPE, has minuscule labor costs that are to be annualized using current employee levels and current salaries. GPE provides common services such as accounting, tax consolidation, corporate legal, and governance to GPE entities. The amount of GPE payroll that relates to KCPL and the GMO entities had to be determined in order to include those costs in the total payroll.

On December 16, 2008, GPE was restructured with all GPE and GPES employees becoming KCPL employees. Because of this restructuring, the allocations factors between KCPL, GMO and GPE heavily favor KCPL, MPS and L&P with GPE having a miniscule factor to account for the above mentioned duties.

Overtime payroll for KCPL and overtime payroll billed to KCPL from the Wolf Creek generating facility were calculated based upon a one-and-a-half year average. This particular timeframe was chosen because the overtime hours and sum paid out indicated an upward trend with the first 6 months of 2010 being noticeably high. These amounts are specific to KCPL, MPS and L&P service territories and, therefore, it is not necessary to include the overtime as part of the allocation process for annualized payroll. The payroll overtime costs have been directly assigned to KCPL, MPS and L&P.

As the result of KCPL’s operating agreements for generating facilities with several partners, it is necessary to assign costs to these partners and remove those payroll costs from the payroll annualization that is reflected in the revenue requirement calculations. This assignment of joint partner billings is necessary to ensure that payroll costs properly billed to the joint partners are not included in the KCPL payroll costs. The level of payroll billed by KCPL to its joint owners in the Iatan and LaCygne generating stations was based upon the June 30, 2010, update period total. Staff used the Company methodology to correctly allocate the reduction in payroll costs from the billing of joint partners, and these costs were removed net of the L&P portion of Iatan before the allocation of payroll to KCPL and GMO. The other payroll costs for partners are billed to The Empire District Electric Company, the other partner in Iatan and to Westar Energy Company, the 50% partner in the two LaCygne generating facilities.

The total annualized GPE and KCPL payroll costs allocated to KCPL also have to be assigned between operational and maintenance ("O&M") expense and other expense. Typically the other expense amount relates to construction and other non-expense functions of a company. The construction amounts are assigned to the work orders for construction projects. The amounts that are included in the revenue requirement calculations for KCPL are the levels assigned to payroll expenses through the O&M expense ratios.

After allocation between expense and construction based on the expense factor, which in File No. ER-2010-0355 is a three-year average, the adjustment for payroll was distributed by individual FERC account based upon the actual distribution for each of those accounts for 12-months ending June 30, 2010, the update period used in this case. Adjustments E-4.1, 5.1, 14.1, 15.1, 16.1, 22.1, 23.1, 24.3, 25.1, 26.1, 60.1, 62.1, 63.1, 67.1, 68.1, 69.1, 70.1, 78.1, 79.1, 30.1, 34.1, 35.1, 36.1, 37.1, 44.1, 45.1, 46.1, 47.1, 48.1, 84.1, 85.1, 86.1, 87.1, 90.1, 95.1, 96.1, 97.1, 98.1, 99.1, 106.1, 107.1, 108.1, 109.1, 110.1, 111.1, 112.1, 113.1, 114.1, 118.1, 119.1, 120.1, 121.1, 124.1, 126.1, 1127.1, 128.1, 129.1, 133.1, 134.1, 135.1, 138.1, 141.1, 142.1, 146.3, 148.1, 151.1, 152.1, 154.1, 158.3, 161.2, 165.1, 171.2, 172.9, 180.1, 181.1, 184.1, 183.1, 186.1, 187.3, 189.1, 191.1, 194.1

*Staff Expert/Witness: Bret G. Prenger*

### 2. Payroll Taxes

Payroll taxes were annualized by applying current payroll tax rates to each employee's annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and partner billings, an aggregate tax rate was applied based on the annualized payroll taxes for base payroll. Wolf Creek payroll has a separate aggregate payroll tax rate applied based on test year billed taxes. The payroll taxes follow the same allocation process used to allocate base payroll. Adjustments E-212.2 and E-212.3 to the Income Statement reflect the annualized payroll taxes based on payroll costs as of June 30, 2010.

*Staff Expert/Witness: Bret G. Prenger*

### 3. Payroll Related Benefits

Staff's annualized 401k expenses were calculated based upon the test year percentage match for KCPL applied to its share of total annualized payroll. In addition, the joint partner share of KCPL 401k expenses was removed from the annual level similar to the annualized payroll adjustment.

Medical costs were calculated based upon twelve months ending June 30, 2010.

Other employee benefits, located in account 926, were calculated based upon the twelve months ending June 30, 2010. Other Benefits include items such as Educational Assistance and Recreational Activities. Adjustments E-172.10, E-172.14, and E-172.15 to the Income Statement reflect the calculated payroll related benefits based on payroll costs as of June 30, 2010.

*Staff Expert/Witness: Bret G. Prenger*

### 4. True-up of Payroll Costs

Staff will update the total payroll costs for the true-up in this case, which is based on an update period ending December 31, 2010. The same methodology used to annualize payroll as of June 30, 2010, will be used for the December 31, 2010, true-up.

*Staff Expert*/Witness*: Bret G. Prenger*

### 5. FAS 87 and FAS 88 Pension Costs

The ER-2009-0089 Pension Stipulation, (referenced above) also addresses the ratemaking treatment for annual pension cost under FAS 87 and pension settlement and curtailment accounting found under FAS 88. The ER-2009-0089 Pension Stipulation reaffirms the agreement memorialized as part of the Regulatory Plan approved by the Commission in Case No. EO-2005-0329 in July 2005. The ER-2009-0089 Pension Stipulation also clarifies the accounting for pension cost allocated to KCPL's joint partners in the Iatan and LaCygne generating stations, and addresses the ratemaking treatment for a curtailment or settlement recognized under FAS 88.

Unlike FAS 87, which allows for a delayed recognition in net periodic pension cost of certain unrecognized amounts, FAS 88 requires the immediate recognition of certain costs arising from settlements and curtailments of defined benefit plans. Without the deferred accounting treatment the Commission approved in Case No. ER-2009-0089, KCPL would have been required to recognize significant FAS 88 pension costs in 2007 as a result of KCPL removing a significant number of employees with accrued pension benefits from the pension plan. This significant cost was primarily a result of KCPL's Talent Assessment Program. When a former employee chooses a lump sum payment for his/her pension plan benefits, a settlement occurs under FAS 88.

In Case No. ER-2006-0314, the Commission approved the Nonunanimous Stipulation and Agreement Regarding Pension Issues ((“ER-2006-0314 Pension Stipulation)”), which first authorized the deferral of FAS 88 costs. For FAS 88 costs, this ER-2006-0314 Stipulation and Agreement authorized the deferral and amortization of the FAS 88 deferral balance over five years beginning with rates established in Case No. ER 2007-0291 in January, 2008. The ER-2006-0314 Pension Stipulation requires KCPL to make contributions to the pension fund annually in amounts sufficient to equal the annual level of FAS 88 pension costs included in the cost of service. Adjustment E-172.3 and E-172.5.5 in the Staff’s accounting schedules represents the five-year amortization of FAS 88 pension costs.

Pension cost under FAS 87 is reflected in the Staff’s accounting schedules in this case, File No. ER 2010-0355, consistent with the ratemaking treatment agreed to in the Stipulation and Agreements approved in KCPL’s Regulatory Plan case, Case No. EO-2005-0329, and KCPL’s most recent rate case, Case No. ER-2009-0089. KCPL’s rate base, discussed previously in Section I, includes the unrecovered balance of the prior Prepaid Pension Asset and the Regulatory Asset which represents the difference between FAS 87 pension costs recovered in rates and FAS 87 pension costs recognized in the financial statements between rate cases. Adjustment E-172.4, is the adjustment in Staff’s accounting schedules to reflect FAS 87 pension costs based upon KCPL’s 2010 actuarial valuation and amortization of the related regulatory asset over five years.

*Staff Expert/Witness: Paul R. Harrison*

### 6. FAS 106 – Other Post Employment Benefit Costs (OPEBs)

Other Post-Employment Benefit Costs (“OPEBs)”) are those costs incurred by the Company to provide certain benefits to retirees. Examples include medical and life insurance benefits. The Company must determine its OPEB expenses based on FAS 106 and Staff has provided sufficient costs in its revenue requirement calculation to reflect a proper level for these post-employment benefit costs.

Section 386.315, RSMo (2000,), requires that the Commission

> …not disallow or refuse to recognize the actual level of expenses the utility is required by Financial Accounting Standard 106 to record for post retirement employee benefits for all the utility's employees, including retirees, if the assumptions and estimates used by a public utility in determining the Financial Accounting Standard 106 expenses have been reviewed and approved by the commission, and such review and approved shall be based on sound actuarial principles.

Financial FAS 106 expenses typically include retiree medical, dental, vision and life insurance benefit costs. Section 386.315, RSMo (2000) requires a utility to "use an independent external funding mechanism that restricts disbursements only for qualified retiree benefits for the FAS 106 costs recognized in a utility's financial statements and that all the funds to be used for employee or retiree benefits."

KCPL is funding its annual FAS 106 costs. Staff Adjustment E-172.8 adjusts KCPL's test year 2009 FAS 106 costs to a level equal to the amount determined by KCPL's outside actuary.

Staff's adjustment annualizes OPEB expenses as calculated under Financial FAS 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* FAS 106, for KCPL's employees. OPEB expense reflects KCPL's current liability to provide retiree medical payments to its current employees as well as its retired employees. Staff used the FAS 106 cost level as reflected in a letter to KCPL from KCPL's actuary, Towers Perrin, received in response to Staff Data Request No. 111. This letter provides the level of FAS 106 OPEB expense booked by the Company for the updated test year period ended December 31, 2009, and the re-measurement cost to shift from fiscal year to calendar year end.

In September 2006, the Financial Accounting Standards Board ("FASB") issued Financial Accounting Standard No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans ("FAS 158"), which amends the above-referenced FAS 87 and FAS 106. FAS 158 requires recognition of the overfunded or underfunded status of pension and other postretirement benefit plans on the balance sheet. These changes were effective for publicly-held entities for fiscal years ending after December 15, 2006. In addition, for fiscal years ending after December 15, 2006, the measurement date is required to be the Employers' fiscal year end. Staff Adjustments E-172.6 and E-172.7 adjusts KCPL's test year 2009 FAS 87 and 106 costs for the shift from fiscal year-end to calendar year-end.

*Staff Expert/Witness: Paul R. Harrison*

### 7. OPEB Tracker

KCPL has requested a tracker mechanism for OPEB expense in this case. Under KCPL's proposal, any excess or deficiency of the Company's OPEB rate allowance, compared to its ongoing level of OPEB expense as determined by its actuary, would be treated as a regulatory asset or liability to be included in KCPL's rate base and amortized, as an addition or reduction to OPEB expense, over a five-year period.

A regulatory asset or liability would be established on the Company's books to track the difference between the level of OPEB expense incurred during the period in which rates are in effect and the level of OPEB expense built into rates for that same period. In this respect the OPEB tracker would work, similar to the pension tracking mechanism. If the OPEB expense during the period is more than the expense built into rates for the period, the Company would establish a regulatory asset. If the OPEB expense during the period is less than the expense built into rates for the period, the Company would decrease any existing regulatory asset or establish a regulatory liability. If the OPEB expense becomes negative, a regulatory liability equal to the difference between the level of OPEB expense built into rates for that period and $0 would be established. Since this is a cash item, the regulatory asset or liability would be included in rate base and amortized over 5 years in the next rate case.

Based upon an analysis of the three previous years of KCPL's OPEB expense, the Staff determined that KCPL's OPEB expense fluctuated significantly from year to year. Therefore, the Staff is not opposed, in concept, to the Company being allowed to track OPEBs expense in a similar manner as it currently tracks pension expense, as detailed in the Stipulation and Agreement in KCPL's last rate case, Case No. ER-2009-0089. By using a tracker, the actual cost of the OPEB expense will be recovered through rates for and from both the rate payer and Company in future rate cases. Both the Company and its customers are protected from paying projected costs in rates in that if the actual costs are less than what is reflected in rates then the tracker mechanism will identify those cost savings for the customers in future rates. Conversely, if costs are greater then what is reflected in rates those costs increases will be captured for future rate case. At the present time The Empire District Electric Company, The Empire District Gas Company and Ameren Missouri have an OPEB tracker.

*Staff Expert/Witness: Paul R. Harrison*

## 8. Supplemental Executive Retirement Plan (SERP) Expense

Included in Staff's revenue requirement recommendation is the actual test-year dollar amount of recurring SERP payments made by KCPL to its former executive employees. A SERP is a pension compensation program which provides benefits to highly-compensated employees over and above the benefits provided under the regular pension plan. In essence, the

SERP is an additional executive benefit because it provides benefits over and above what is provided under the regular – all employee pension plan.

In the 2009 test year in this case, KCPL paid $168,140 in recurring annual SERP payments to a total of eight retired former officers. This amount has remained exactly the same since 2002 and this is the amount that Staff has included in KCPL's cost of service recommendation in this case. In adjustment E-172.1 the Staff removed the test year per book accruals for SERP costs. In adjustment E-172.2 the Staff included KCPL's total SERP payments made in 2009.

*Staff Expert/Witness: Charles R. Hyneman*

### 9. Severance Costs

KCPL is proposing to recover a three-year average (2007 through 2009) of severance payments to terminated employees. This proposal is reflected in KCPL's adjustment CS-55. Staff is opposed to severance costs that do not produce any customer benefit and are likely to have already been recovered in rates through regulatory lag. In adjustments E-135.1 and E-158.1, the Staff removed KCPL's 2009 test year severance payments.

These severance payments made by KCPL are not recurring costs that should be borne by regulated customers. These payments will not result in any payroll savings costs, and lack support that they will ever provide any benefit to KCPL or its customers, now or in the future. In addition, by seeking rate recovery of severance payments, KCPL ignores the fact that, until rates change, payroll expenses for the severed employee continue to be recovered in rates after the employee leaves the Company. In many instances this timing issue leads to recovery of the actual amount of severance payments made many times over. This over-recovery of an expense occurs through the regulatory phenomenon called "regulatory lag." Through regulatory lag, KCPL continues to recover a severed employees' salary and benefis, such as medical insurance and retirement benefits in utility rates until either 1) that position is filled with an employee at that comparable salary and benefits and the payroll and benefits costs are again incurred, or 2) until the reduced employee level (the fact that the severed employee is no longer on the payroll and benefits expense that is developed in a rate case) is reflected in rates in the next rate proceeding.

*Staff Expert/Witness: Charles R. Hyneman*

### 10. Talent Assessment Amortization

In Case No. ER-2007-0291 KCPL proposed the recovery in rates of what it referred to as "Talent Assessment" or "Skill Set Realignment" costs. These costs were primarily severance payments to either employees whose employment was terminated by KCPL or employees who elected to leave KCPL. The total cost of the severance program, according to KCPL, was approximately $9.6 million for the termination of 119 KCPL employees. The Missouri jurisdictional portion of those costs, as allocated by KCPL, was $4,840,517. In its test year income statement in this case, KCPL amortized $968,103 (adjustment CS-101) of this total deferral to expense in account 920. The Staff's adjustment, E-159 in this case removes this amortization from KCPL's cost of service.

In KCPL's 2007 rate case the Staff opposed rate recovery of these Talent Assessment severance payments; however, the Commission, in its Report and Order in that case, Case No. ER-2007-0291, found this issue in KCPL's favor based on KCPL testimony that this program is and will be beneficial to KCPL's customers. The Commission concluded that the Talent Assessment severance costs should be recognized in cost of service, and amortized to expense over five (5) years commencing January 2007.

In its audit of KCPL's last rate increase proposal, Case No. ER-2009-0089, the Staff found strong evidence that KCPL's Talent Assessment Program did not produce the benefits KCPL hoped it would produce. In fact, the Staff found that no future economic benefit (the definition of an asset) existed from the Talent Assessment Program. In Staff's revenue requirement recommendation in Case No. ER-2009-0089 the Staff did not include the Talent Assessment amortization on the basis that the Commission's allowance of rate recovery of these severance costs, that they would produce actual ratepayer benefit, did not exist at that time.

In its Report and Order in Case No. ER-2007-0291 at page 53 the Commission explained the basis for its decision to allow direct rate recovery of KCPL's Talent Assessment costs in that case as follows:

> …Common sense dictates that a company that is run more efficiently makes more money, at least in part because a higher level of efficiency results in happier customers. Indeed, the record is replete with evidence that KCPL's customer service is excellent. What is more, KCPL's ranking among Midwestern public utilities rose from eighth to fourth in 2006, according to a J.D. Powers and Associates survey, with those rankings measuring such components as power quality and reliability and customer service.

In its Cost of Service Report in Case No. ER-2009-0089 ("2009 COS Report"), the Staff found that KCPL's Missouri residential customers were significantly less satisfied with KCPL in 2008 then they were in 2007. As related in the Post-Consolidation Service Quality section of the 2009 COS Report, (page 161) the number of KCPL residential customer complaints increased substantially from 2007 to 2008, from 217 to 320. In addition to the increased unhappiness of KCPL's residential customers, according to the JD Powers and Associates survey for business customers for 2008, KCPL's ranking and scores deteriorated significantly.

In the J.D. Powers and Associates Business Customer Study for 2007, released in March 2007, KCPL's score was 725 as compared to Aquila's 694 and the Midwest average of 670. However, in the J.D. Powers and Associates Business Customer Study for 2008, released in February 2008, KCPL's score declined to from 725 to 704 while Aquila's score increased from 694 to 719 during this same period. This significant decrease in KCPL's business customer satisfaction occurred in a time period when business customer satisfaction with electric utility providers had reached record high levels across the nation, as noted in the JD Powers & Associates press release announcing the results of its survey. In a February 2009 Electric Utility Business Customer Satisfaction Study, KCPL's index score dropped from 704 in 2008 to 632 in 2009 and was ranked 9th out of 23 Midwest Region utilities in that survey.

KCPL's ranking in the February 2010 and July 2010 Electric Utility Business Customer Satisfaction Study did improve significantly. In the July 2010 Study, in comparison to 11 other Midwest large electric utilities in categories such as Billing & Payment, Price, Customer Satisfaction, Power Quality and Reliability, Communications and Corporate Citizenship, KCPL ranked first in several categories and not lower than third in any category. KCPL's JD Power's residential customers surveys in 2010 were also respectable, with KCPL falling near the bottom of the first quartile in many categories.

However, whether KCPL's JD Power scores go up or down, there is great difficulty making any association at all with the JD Power scores and the impact of KCPL's Talent Assessment Program. One major problem in making that association is the fact that the JD Power survey results in 2009 and 2010 are not for the same utility as the survey results for 2008 and prior to 2008. The old KCPL no longer exists. It now operates as a combined company with the former Aquila, Inc., now referred to as GMO as KCP&L.

How much impact on the JP Power scores did KCPL's acquisition of Aquila really have? How many customers who responded to the survey were actually former Aquila, now

KCPL-GMO customers? Since the 2009 JD Power surveys report GMO customers as KCPL customers, there is no way to determine.

Another major problem in making any association with the Talent Assessment Program and the JD Power survey results is the extremely small percentage of KCPL (actually KCPL and GMO) customers who responded to the survey. For example, in the 2010 Electric Utility Residential Customer Satisfaction Study, JD Power received only 1,917 responses out of a total of 718,746 (the number reported by JD Power) residential customer accounts. This means that conclusions about KCPL's customer service is being based on the input of less than one-half of one percent of its customers. While the Staff has not done a statistical analysis to determine if any reliable inference about customer service can be made with such a small sample size, the extremely small sample size does pose questions about the reliability of the study and the prudence of making any financial decisions based on such limited information.

In looking at the evidence of whether not the Talent Assessment Program has produced any customer benefits, reliance on JD Power survey results alone is not a prudent course of action. As it did in Case No. ER-2009-0089, the Staff also looked at the number of complaints made against KCPL by its Missouri customers. Since the number of customer complaints is now tracked in the Commission's EFIS system, the Staff obtained the number of KCPL customer complaints (excluding GMO) for the calendar years 2008, 2009 and the twelve months ended October 2010. In calendar year 2008 the number of complaints were 260. In 2009 this number increased by 15 percent to 298. In the twelve months ended October 31, 2010, KCPL logged 305 complaints.

The Staff wants to be clear that it is not making any inference about the quality of KCPL's overall customer service based on this analysis. However, the Staff does believe the increases in KCPL complaints is sufficient evidence to conclude that it is more likely than not that the Talent Assessment Program has not produced any tangible customer benefit over this period. Based on this conclusion, and the conclusion reached in Case No. ER-2009-0089, the Staff does not believe KCPL should continue to recover the cost of the Talent Assessment Program in rates.

Is it common for the Staff to assess the value of the assets on a utility's balance sheet, especially intangible assets such as regulatory assets, to ensure the costs that formed the basis of the assets have in fact created actual benefits to the utility and its customers.

This procedure is referred to as an asset impairment test. During its rate audit, the Staff performs functions and has responsibilities similar to KCPL's external auditors as certified public accountants (CPAs). The auditors in the auditing firm that KCPL engages to audit its external financial statements have a specific responsibility to review the carrying amount of assets to make sure that the value of the assets carried on the financial statements are at least equal to be benefits expected to be realized by the use of the assets. If these auditors find that the cost of an asset recorded on KCPL's books and records are overstated compared to the expected future benefits of the asset, the auditors are required to make KCPL's management aware of this fact and insist on an appropriate write-down of this asset. If these auditors, after reaching this conclusion, fail to take the appropriate action, they may be subject to disciplinary actions based on unethical conduct and/or failing to exercise due professional care in the performance of the audit, one of the generally accepted auditing standards (GAAS).

The Staff also has this responsibility in developing its revenue requirement recommendation to the Commission in this rate case. The Staff has a responsibility to recommend to the Commission a revenue requirement that it believes will result in just and reasonable rates based upon a Company's actual cost of providing service to its customers. Including in its revenue requirement proposal the cost of assets that it believes have not and are not producing benefits to customers would be inappropriate and a potential violation of GAAS.

It is common for utility company accountants to assess the carrying value of assets based on current and expected future benefits and to write-down or reduce the carrying amount of assets that do not continue to produce real economic benefits. In fact, this type of asset evaluation is required by generally accepted accounting principles (GAAP) and is an action that is performed routinely by KCPL's accountants.

A significant amount of these costs have already been recovered in rates. As ordered by the Commission Order in Case No. ER-2007-0291, KCPL deferred Talent Assessment Severance Program expenses (severance, outplacement, payroll taxes, etc.) as a regulatory "asset" and began to amortize this asset to expense over five (5) years starting in January 2008, when rates from the 2007 rate case went into effect. By the time new rates from this case are anticipated to be in effect May 2011, KCPL will have directly recovered through rates approximately sixty-seven (67) percent of the $4.8 million deferral or $3.2 million. KCPL's regulated customers will have directly paid two-thirds (2/3) of the total costs of the Talent Assessment Program when there is significant doubt whether or not any of the customer benefits promised by KCPL ever existed.

The Staff recommends that the Commission find, based on the above described evidence, that KCPL's cost of severing the 119 employees, referred to as the cost of the Talent Assessment Program, did not result in the expected customer benefit and, therefore, not include the $968,000 annual amortization of the 5-year deferral as an adjustment to increase KCPL's revenue requirement in this case. In Staff's view, KCPL's rate recovery of approximately two-third (2/3) of the cost of the talent assessment program is more than adequate recovery of any actual benefits customers may have obtained from KCPL's Talent Assessment Program during the period evaluated by the Commission in its ER-2007-0291 Report and Order.

*Staff Expert/Witness: Charles R. Hyneman*

## 11. Short Term Annual Incentive Compensation

KCPL has three separate, short-term annual incentive compensation programs for executive, management, and union employees. These programs are designed to grant cash awards of various amounts calculated based upon designated annual metrics. The timing of the payout for amounts accrued under the terms of each program during the year is during the first quarter of the following calendar year. The three incentive compensation programs are: 1) The Rewards program, reserved for bargaining (union) employees; 2) The Value-link program, reserved for management-level KCPL employees; and 3) The Annual Executive Incentive Plan, reserved for senior KCPL management employees.

In prior plan years KCPL's program was designed with a "trigger", an Earnings Per Share "EPS" threshold that was to be met before any employee received any funds under the plans. However, if the "trigger" was not met, the plans dictated that no payouts were to be made, regardless of any achievement of goals, financial or otherwise. This mechanism has been removed for all plans beginning during the 2009 plan year and consequently reduces the volatility of payouts from year to year. This contrasts the two prior years when the threshold EPS was not met and no funds were available for payout under the incentive plans.

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.

The Rewards program covers bargaining unit employees from IBEW Local 1464 (approximately 691 employees), IBEW Local 412 (approximately 834 employees), and IBEW Local 1613 Unions (approximately 417 part/full time employees). ** **

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The Value-link program covers non-executive management-level KCPL employees, such as Plant Manager or Insurance Manager. **



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The third short term annual incentive plan is the Annual Executive Incentive Plan ("the Executive Plan"), designed for the top 22 officers of the Company. **

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In its direct case, KCPL did not include the 40% based on Earnings Per Share and 20% discretionary portion of the Annual Executive Incentive Plan in the cost of service as the result of KCPL Adjustment CS-51. Remaining in the cost of service are the projected payouts at the target level for salaries as of June 30, 2010 as updated by the Company. Staff has proposed to remove the amounts the Company did not include in the cost of service in its direct filing in prior cases, namely ER-2006-0314 and ER-2007-0291. In those cases, the Commission adopted Staff's position. Staff would have proposed a similar adjustment to incentive compensation if the full amount were included in the cost of service.

While Staff agrees with the adjustments KCPL has made in this case, it continues to evaluate the Company's philosophy on compensation and benefits. Incentive compensation is but one factor in KCPL's total pay and benefits package, in addition to deferred compensation, pension, and health and welfare benefits. Adjustment E-172.21 to the Income Statement is to remove costs relating to the short term incentive compensation for the test year 2009. The adjustment amount in File No. ER-2010-0355 is ($1,747,489) Adjustment E-172.13

*Staff Expert/Witness: Bret G. Prenger*

### 12. Long-Term Incentive Compensation

The Long Term Incentive Compensation Plan for the 2009-2011 calendar years was based on two goals each weighted at 50%. The two goals were FFO to Total Adjusted Debt and Earnings Per Share (EPS). The purpose of the plan was to encourage executive and other key KCPL employees to acquire a vested interest in the growth of and performance of Great Plains Energy. Eligible employees include executives and other employees of GPE and KCPL as approved by the Compensation and Development Committee of the Board of Directors. The awards generally given are 50% restricted stock with the number of shares determined at the date of grant based upon the GPE stock price. The other 50% of the awards will be performance shares with that number granted to be determined by the Fair Market Value at date of grant. Time-based restricted awards and performance shares will be payable in GPE common stock. As part of KCPL Adjustment CS-11, the Company removed all costs associated with long-term officer incentives stating "the costs are ordinary and reasonable business expenses; however, we do not believe such costs should be borne by ratepayers." Staff agrees with the adjustment and has included it in the cost of service. The adjustment amount in File No. ER-2010-0355 is ($4,367,779) Adjustment E-158.4

*Staff Expert/Witness: Bret G. Prenger*

### C. 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 Uniform System of Accounts ("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 2009 through June 30, 2010, 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 specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff annualized reflecting the price increases for labor that generally occurs each year. A detailed staff position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report. The maintenance analysis was done only on non-wage maintenance and operating costs.

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 the 2009 Test Year. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs. Staff's results are presented in the following table;

| **Results of Staff's Non-Labor Maintenance Analysis** | |
|---|---|
| Steam Production Maintenance | 2-Year Average (2008-2009) |
| Nuclear Production Maintenance | 2009 Test Year |
| Other Production Maintenance | 2009 Test Year |
| Transmission Maintenance | 2009 Test Year |
| Distribution Maintenance | 2009 Test Year |

As identified in the table above, Staff made a decision to use the 2009 test year account balances to represent future maintenance costs for Nuclear, Other Production, Transmission, Distribution and General Maintenance. Staff used the 2009 test year to reflect a level of normalized maintenance for these plant investments based on actual information provided by the Company for a period of several years. This historical information was analyzed to determine the proper level of maintenance which should be included in this case.

For Wolf Creek, there are two types of O&M costs – 1. O&M for general plant and 2. O&M relating to the refueling outages that occurs every 18 months. Staff performs a separate analysis for nuclear refueling outages. A discussion for Wolf Creek's refueling is located under the heading *Wolf Creek Nuclear Refueling Outage* in this report. The adjustments for Production Maintenance are E-22.2, E-23.3, E-24.1, E-25.2, and E-26.2.

*Staff Expert/Witness: Karen Lyons*

### 1. Wolf Creek Nuclear Refueling Outage

Staff reviewed information for the last five nuclear refueling outages. As a result, Staff included an annualized amount based on the most current refueling outage #17 that occurred in 2009. Staff found during its review, refueling costs have increased over the last two refuelings—refueling outage #16 and #17. Staff has requested additional documentation to determine the reasons for the increased costs. Once this information is received, Staff will examine the reasons for the increased Wolf Creek O&M costs for refueling outages. Staff may propose any additional adjustments to normalize the refueling outages if necessary to determine an appropriate level of O&M expense for the Wolf Creek refueling outage.

In addition, Staff made an adjustment for the refueling amortization established in the Stipulation Agreement in Case No. ER-2009-0089. KCPL deferred and amortized the actual cost incurred during the Wolf Creek refueling outage over 18 months (the time period between refueling outages). The outage periods for 2003 refueling #13 was 45 days; the outage period for 2005 refueling #14 was 40 days and the outage period for 2006 refueling #15 was 34 days. In contrast, the outage period for the 2008 refueling #16 was 55 days and the 2009 refueling #17 was 59 days. The average outage period for the three refueling periods occurring in 2003, 2005, and 2006 was 40 days. The 2009 refueling that lasted 59 days represented an increase of 48 percent above the average refueling outage days [average 40 days compared to 59 days]. Because of this abnormal event, the refueling costs of the outage increased significantly. KCPL and other signatory parties agreed through a Stipulation and Agreement in Case ER-2009-0089 to defer the cost of Outage #16 O&M refueling over a five year period. In the Stipulation and Agreement issued in Case No. ER-2009-0089 the Commission stated the following:

> The Signatory Parties agree that $1,570,581 (Missouri jurisdictional) of Outage #16 O & M refueling costs will be deferred in a regulatory asset account and amortized over five years beginning with the date new rates become effective in this case, with one-fifth of this cost included in cost of service in this case. The unamortized balance will not be included in rate base.

The deferral of the amortized refueling amount began on September 1, 2009 and will end September 1, 2014. As a result of the Stipulation and Agreement, Staff made an adjustment for one-fifth of the total costs of Wolf Creek Refueling Outage #16. Adjustments E-37.3 and E-46.2 are for Wolf Creeks refueling outage #16 per agreement in Case No. ER-2009-0089. Adjustments E 37.4 and E-46.3 are for Wolf Creek refueling outage #17 occurring in the 2009 test year.

*Staff Expert/Witness: Karen Lyons*

## 2. Nuclear Decommissioning

In its Report and Order in Case No. ER-2006-0314, the Commission ordered the following:

> 1) KCPL's annual Missouri retail jurisdictional decommissioning cost accrual shall be $1,281,264, commencing January 2007 and KCPL's decommissioning trust fund payments shall be at that annual level;
>
> 2) Decommissioning cost accruals, as a consequence of "1)," will continue to be included in KCPL's cost of service and will continue to be included in KCPL's rates for ratemaking purposes;

After reviewing the Company work papers, Staff found the test year reflected an amount less then what was ordered by the Commission. The Company made an adjustment to reflect the difference of what was ordered in Case No. ER-2006-0314. Staff issued an adjustment to mirror the Company adjustment issued in this case. Adjustment E-38.1.

*Staff Expert/Witness: Karen Lyons*

## 3. Nuclear Decommissioning Trust Fund Contributions

Staff recommends no change to the Company's current level of Nuclear Decommissioning Trust Fund ("Trust Fund") contributions. KCPL's current annual contribution level of $1,281,264 was established in KCPL's 2006 general rate case, Case No. ER-2006-0314. This contribution level was premised on an expected return of 6.48 percent for the Trust Fund portfolio. GPE currently has a lower expected return for its pension assets than it did in 2006. If these same lower return expectations were factored into contribution requirements for the Trust Fund, this would provide support for an increase in the annual level of Trust Fund contributions. However, because there are other uncertainties regarding other Trust Fund assumptions (e.g. cost to decommission and the proper cost inflation rate) Staff believes it is acceptable to maintain the current contribution level.

*Staff Expert/Witness: David Murray*

### <u>4. Iatan 2 O&M Expenses</u>

Iatan 2 met its in–service criteria on August 26, 2010. Iatan 2 has been included in the Estimated True-up Case through the December 31, 2010. Staff will include KCPL's estimated amounts for KCPL's share of Iatan 2 O&M expenses in its true-up filing, for the true-up period ending December 31, 2010.

Staff recommends the Commission authorize a tracker for Iatan 2 O&M expense, so the actual cost of the O&M expense related to Iatan 2 will be recovered through rates for both the rate payer and Company in future rate cases. Given KCPL's very limited operation experience with Iatan 2 at this time, a tracker protects both KCPL and its customers from including projected costs in rates that will in all likelihood vary from the actual costs associated with Iatan 2's O&M expense.

*Staff Expert/Witness: Karen Lyons*

## D. Depreciation - Clearing

During the test year, the Company included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to remove the depreciation amount booked to the clearing account. Adjustment E-191.2

*Staff Expert/Witness: Karen Lyons*

## E. Other Non-Labor Adjustments

### 1. Hawthorn 5 SCR Impairment adjustment

After the February 1999 explosion, which entirely destroyed the boiler, Babcock & Wilcox (B&W) and KCPL entered into an engineering, procurement, and construction agreement with KCPL for the construction of Hawthorn Unit 5 boiler island (B&W Agreement). The Agreement required B&W to install a selective catalytic reduction system (SCR) at Hawthorn Unit 5. This environmental equipment was installed to reduce pollution associated with operating a coal-fired generating unit. Under the Agreement, B&W guaranteed specific performance standards, including an ammonia slip test. After the SCR was placed in service in 2001, the boiler failed the ammonia slip test. The guaranteed performance standards were part of the contractual agreement between B&W and KCPL that required KCPL to pay for the SCR equipment.

In 2002, KCPL and B&W tried to resolve the issues by B&W doing additional work. Problems with the equipment still existed in 2004. After that point, B&W and KCPL entered in to a Memorandum of Understanding (MOU), and revised the requirements of the ammonia slip test standards. This revision lowered B&W standards regarding the ammonia slip test. Subsequently, B&W failed to meet these revised lowered standards. Because of B&W's failure to meet the ammonia slip test standards, KCPL experienced increased replacements of catalysts, increased usage of ammonia, plus additional cleaning and maintenance expense all resulting in significantly higher than expected costs to run and maintain the SCR equipment. After the revised standards could not be met, KCPL requested liquidated damages from B&W based on the difference between the costs KCPL would incur if the standards were met and what costs KCPL incurred because the standards were not met.

In 2007, KCPL received a settlement from B&W as recognition of the higher costs to operate this generating unit. The performance standards were never met. The settlement in essence recognized a lower performing piece of equipment which would require higher operating and maintenance costs over the life of the unit. This resulted in higher rates for the customers.

KCPL paid for higher plant costs for the higher performance standards that were never met—the higher plant costs are reflected in rates. All litigation and settlement discussions were handled in-house by KCPL attorneys, thus the labor costs were paid for by the customers. The increased costs for the ammonia slip tests, more frequent replacements of catalysts, and increased cleaning and maintenance expense continue to exist today resulting in higher costs which the customers are required to pay. KCPL has and continues to experience higher operating and maintenance costs at Hawthorn 5 as the direct result of the performance failure of the SCR. All the higher operating and maintenance costs are included in rates paid by KCPL's customers. The settlement amount paid by B&W was retained by KCPL to be passed on to Great Plains Energy shareholders.

The Staff's position is that KCPL's customers should receive the benefit of the settlement with B&W since they paid the costs KCPL incurred because of the substandard performance of the plant. All the increased costs to KCPL were and are currently being paid by KCPL customers in utility rates. These costs include the salaries and benefits, office space, and all employee-related costs of KCPL's attorneys and employees who worked on this dispute between KCPL and B&W.

One position is to reflect the settlement as an increase to depreciation reserve. Using this approach causes plant to be overstated which in turn causes depreciation to be overstated. Therefore, an adjustment to reduce depreciation expense is also necessary. Staff made an adjustment to increase depreciation reserve by the settlement amount and made an adjustment to decrease depreciation expense. Adjustment R-21 and P-160.1.

Although increasing depreciation reserve is one method of accounting for receipt of settlements, Staff believes an alternative accounting method – that is preferred – should be considered. As mentioned above, making an adjustment to depreciation reserve does not correct the overstated plant. The overstated plant results in higher depreciation expense. Staff believes an adjustment to reduce plant and a corresponding adjustment to correct the depreciation reserve to reflect the settlement with B&W is necessary to properly reflect the true value of the plant investment which has lower performance standards for the operation of the SCR. The lower performance standard would have resulted in a lower price for the plant, therefore the plant investment reflected in rate base would not be overstated as it currently exists. By reducing the plant amount for the settlement, no other adjustment is necessary to reduce depreciation expense since plant will be properly accounted. Under the plant method, depreciation has occurred since the time of the settlements resulting in an increase to depreciation reserve. If an adjustment to reduce plant is made then it would be appropriate to adjust depreciation and deferred income taxes. Making these adjustments to "correct" the plant, depreciation reserve and deferred income reserve balances will result in no further adjustments being necessary in the future.

On the other hand, the accepted method of increasing depreciation reserve for the settlement amount does not correct the overstated plant and therefore; future adjustments to reduce depreciation expense will be required.

*Staff Expert/Witness: Karen Lyons*

## 2. Hawthorn 5 Transformer Settlement

In August 2005, the generator step-up transformer (step-up transformer) on KCPL's Hawthorn 5 failed. In September 2005, a backup step-up transformer was installed. During June 2006, a new step-up transformer was installed. KCPL sued the contractors and subcontractors claiming they were responsible for the step-up transformer failure. The case settled at the end of 2007, and was finalized in 2008. KCPL received a dollar settlement for the transformer failure. KCPL has made no adjustment in its books and records to provide any benefit of this settlement to its customers. It is Staff's position that KCPL's customers should receive the benefit of the settlement since they are the ones who paid higher costs for the substandard plant performance.

All the increased costs to KCPL of the operation of Hawthorn 5 resulting from the step-up transformer failure were paid by KCPL customers in its utility rates. These costs include the salaries and benefits, office space, and all employee-related costs of KCPL's attorneys and employees who worked on KCPL's dispute with the contractors and subcontractors, increased maintenance, fuel and purchased power expense, and increased expenses that were capitalized to the new plant.

It is Staff's initial position to reflect the settlement as an increase to depreciation reserve. However, similar to the Hawthorn SCR settlement, increasing depreciation reserve does not correct the overstated plant and depreciation expense. Staff made an adjustment to reduce depreciation expense. Adjustment R-25 and P-160.1.

Although increasing depreciation reserve is one method of accounting for this type of issue, Staff believes an alternative accounting method should be considered. As mentioned above, making an adjustment to depreciation reserve does not correct the overstated plant. The overstated plant results in higher depreciation expense. Staff believes an adjustment to reduce plant and a corresponding adjustment to depreciation reserve to reflect the settlement with B&W is necessary to properly reflect the true value of the plant investment which has lower performance standards for the operation of the SCR. The lower performance standard would have resulted in a lower price of the plant, therefore the plant investment reflected in rate base is overstated as it currently exists. Using this approach, no other adjustment is necessary to reduce depreciation expense since plant will be properly accounted. Making both of these adjustments to plant and reserve will result in no further adjustments being necessary in the future.

On the other hand, the accepted method of increasing depreciation reserve for the settlement amount does not correct the overstated plant and therefore; future adjustments to reduce depreciation expense will be required.

*Staff Expert/Witness: Karen Lyons*

### <u>3. Leases—Adjustments E-190.1 and E-190.2</u>

Lease costs are those costs incurred by KCPL for the leasing of its corporate headquarters. Staff examined these costs for test year 2009 and updated them through June 30, 2010. KCPL moved its corporate headquarters to One Kansas City Place, 1200 Main Street, Kansas City MO. (During the fourth quarter of 2009)

Staff recognized the monthly base rent for the headquarters and multiplied that by 12 months to reflect an annualized rent amount. In addition to the lease rent amount, the Company has to pay other costs for customer and employee parking, as well as the annual cost for the building's electricity. KCPL currently rents four classifications of parking spaces: Visitor, Reserved, High Profile Vehicles, and Unreserved. To calculate an annualized amount for parking, Staff took the number of spaces provided in each category times the monthly rate, then applied that total times 12 months. Also, Staff picked up the adjustments of the Company to back out amounts that were associated with other standard parking accounts, so as to avoid double-counting this expense. KCPL pays electricity at a rate per square foot leased for the building. Once the three portions of the lease expenses are totaled (base rent, parking, and electricity) those amounts are then allocated out between KCPL, GMO, and GPE.

When the Company relocated to the new location, it was allowed 270 days (9 months) of rent free time, called an abatement period. Staff calculated an adjustment to reflect the "free rent" over a 5 year timeframe, and adjusted it out of the test year lease expense. The calculation of this adjustment was handled in a very similar manner to the corporate headquarters lease adjustment. Staff took the base rent and parking expenses and instead of annualizing them for a full 12 months, did the multiplication times a 9 month period.

The Staff adjusted the Company's test year amount for lease rent during the substantial period of time KCPL was paying the final months of its lease at its previous headquarters and paying leasing payments on its new corporate headquarters while it was being renovated. The leasehold adjustment results in a decrease of ($1,669,286) in Total Company lease expense that is identified as Adjustment E-190.1. An additional adjustment is being made to reflect the decrease of ($586,390) for the abatement period—this is identified as Adjustment E-190.2

*Staff Expert/Witness: Bret G. Prenger*

### **<u>4. Property Tax Expense</u>**

Each year KCPL is billed by each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property KCPL owns exclusively on January 1st of that calendar year. The property taxes assessed on January 1 of each year are typically not due to the taxing authorities until December 31 of that same year, and in the state of Kansas, part 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 ending December 31, 2009, updated through June 2010. Since the update period in this case is June 30, 2010, Staff determined the annualized property taxes based on the property KCPL had in-service on January 1, 2010. Staff applied a property tax ratio based on actual 2009 property tax payments to January 1, 2009 plant. This ratio of property taxes when applied to the January 1, 2010 plant provides the amount of property taxes expected to be paid for 2010. Since the actual 2010 property taxes owed by the Company have not been paid as of the update period, June 30, 2010, Staff plans on updating KCPL's property taxes for the true-up which will be through December 31, 2010. Because the update in this case is June 30, property tax expenses for 2010 were annualized as of the January 1, 2010 date. This calculation is an estimate of the total 2010 property tax expense. Both Staff and the Company typically accomplished this by looking to the tax rate paid for the previous year, and then applying it 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 owned on January 1, 2010, and then applied to it the tax rate assessed to the Company in 2009. The property tax rate assessed in 2009 is calculated by dividing the total amount of property tax paid by the Company by the total cost of the taxable property owned on January 1, 2009. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2010. Staff believes that the property tax expense arrived in this manner is the best available information, since it relies on the actual January 1, 2010 balance of KCPL's property, and uses the most recent, known tax rate (2009), without attempting to estimate any change in the rate of taxation for 2010 that is not known as of the update period June 30, 2010. The property taxes will be trued-up during that phase of the case.

During the true-up Staff will examined the actual amount paid for property taxes for 2010 as that amount will be known at the end of the year.

Staff adjusted test year property tax expense in order to include in rates the annualized level of 2010 property taxes. Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in prior cases, most recently 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.

Based on the methodology addressed earlier, Staff made an adjustment to include an annualized amount for property taxes. Adjustment E-120.1 reflects the annualized levels.

*Staff Expert/Witness: Karen Lyons*

## 5. 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 amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense.

Staff calculated the annualized bad debt expense by examining the billed revenues, net of gross receipt taxes for the twelve months period ending December 31, 2009, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending June 30, 2010. From this information a bad debt ratio was derived, which was then applied to Staff's annualized 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.

The Company 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. This is Adjustment E-136.1.

*Staff Expert/Witness: Amanda C McMellen*

### 6. Advertising Expense

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission followed as a result of the 1986 Kansas City Power & Light rate case, (Case No. EO-2005-0329 beginning with the 2006 rate case, Case No. ER-2006-0314). In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL), the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

1. General: advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;

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

5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because it believed that a utility's revenue requirement should: "1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement." (Report and Order in KCPL Case No. EO-85-185, 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)).

In response to data requests, KCPL provided a list of all costs associated with advertising and a brief description of those costs. Staff held multiple meetings and phone discussions with KCPL to review these costs and ask questions regarding the Company's implementation of its new "Connections" program. The purpose of Staff's review of KCPL's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in KCPL's cost of service. For example, all costs for safety advertising and indirectly related to safety advertising were included as well as other costs necessary for KCPL to communicate with its customers on utility matters. Staff removed test year expenses incurred by KCPL for advertising programs that are appropriately classified as institutional image in nature.

Following the Company/Staff meetings, Staff has come to the conclusion to make adjustments to account 908.000 and 909.000, as well as pick up the Company adjustments to accounts 913.000 and 930.100. The 908 account represents The KCPL Connections program, and while certain aspects of the program are beneficial, Staff believes a significant portion of the program represents costs pertaining to CEP/Energy Efficiency and DSM. Staff choose to expense 50% of the costs and then capitalize the other 50% of the costs dealing with this program. (Adjustment E-142.3) Account 909 deals with general advertising costs in which after review, Staff found several costs also associated with CEP and Energy Efficiency. Based on the handling of these costs in case ER-2009-0089, Staff believes they should also be capitalized. (Adjustment E-146.3) Finally, Staff chose to pick up two Company adjustments for accounts 913 and 930.1 that simply reflect the change between test year and known and measureable. (Adjustments E-153.1 and E-187.1)

Staff focused on campaigns, not individual advertisements, which is consistent with the Commission's discussion on the topic as stated in its most recent rate case order, the AmerenUE Report and Order in ER-2008-0318. Adjustments E-142.3, E-146.1, E-146.2, E-153.1, E-187.1 and E-187.2

*Staff Expert/Witness: Bret G. Prenger*

### 7. 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. Consistent with Staff policy for many years, Staff included all dues payments made by KCPL to each area's Chamber of Commerce, and removed the other dues as costs not necessary in the provision of utility service. This adjustment was made to KCPL account 930.2. In addition to this adjustment, Staff removed costs in which it considers the expenses to be personal or of no benefit to the ratepayer and thus, not included in a utility's cost of service. Staff also removed costs associated with Dollar-Aide contributions, E-189.5. Adjustments E-189.2 and E-189.5

*Staff Expert/Witness: Bret G. Prenger*

## 8. 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 receipt taxes (GRTs), 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, the Company periodically remits these amounts to the appropriate taxing authorities. In this regard, to accurately account for the Company's actual test year retail revenues – it is necessary to remove GRTs from the amounts recorded as 2009 revenues – while at the same time removing the corresponding remittances to the taxing authority as a charge to expense. In effect, GRTs will have no impact on the Company's final revenue requirement amount. Staff's adjustments remove GRTs from test year revenues and expenses. The adjustments are Rev-3.1, Rev-18.2 and E-213.1.

*Staff Expert/Witness: Amanda C McMellen*

## 9. Debit/Credit Card Acceptance Program

In February 2007, KCPL implemented a Credit/Debit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. The program is offered by KCPL in an agreement with Western Union through its SpeedPay service, which acts as a third party facilitator for the processing of payments to KCPL. When payment is made by a customer through the credit or debit card system, KCPL will receive payment from Western Union. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and or by registering on KCPL's website. Payment through the website offers two options one time payments or what the Company terms the, "recurring card payment option," which is available through registration on its website. 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 will decline.

Staff has 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 six months ending June 30, 2010 multiplied by two, which represents an ongoing level of costs. This adjustment is represented in Staff's Accounting Schedules as E-135.3.

*Staff Expert/Witness: Amanda C McMellen*

## 10. KCPL Receivables Bank Fees

KCPL sells its accounts receivable; as described on page 3, lines 1-15, of the Direct Testimony of KCPL witness Michael W. Cline. The process is as follows:

- KCPL sells all of its receivables daily at a discount and on a non-recourse basis to Kansas City Receivables Corporation ("KCREC")
- KCREC gives a promissory note to KCPL for the amount of the discounted receivables purchased
- KCREC sells an undivided interest in the receivables to a bank conduit – Victory Receivables Corp.
- The bank conduit issues A-1/P-1 Commercial Paper to fund the purchase of the receivables from KCPL
- The bank conduit advances funds to KCREC, which uses the funds to reduce the promissory note given to KCPL
- KCREC pays KCPL a collection fee to collect the receivables monthly
- KCREC pays Victory the Commercial Paper fees plus a monthly program fee
- KCREC pays KCPL interest due on the promissory note monthly

In June 2009, KCPL renegotiated its contract with KCREC which resulted in an increase in the purchase limit of receivables. As a result, the percentage of receivables sold increased resulting in decrease in the collection lag. Staff reflected the benefit of selling accounts receivables as a reduction in the revenue lag, in the cash working capital amount determined in this case. The selling of accounts receivables results in the Company collecting revenues on an accelerated basis from lending institution. The benefit to the Company is that it receives enhancement to its cash management. For rate making purposes, this enhancement is reflected in the acceleration of the collection process identified through a shorter revenue lag in the CWC schedule than otherwise would have occurred absence the sell of the accounts receivables. The adjustment for bank fees relates to the cost of this program. Staff included an annualized level of bank fees paid by KCPL to KCREC in Adjustment E-133.2, Schedule 9.

*Staff Expert/Witness: Karen Lyons*

## 11. Miscellaneous Test Year Adjustments

In its direct filing, KCPL proposed Adjustment CS-11 which includes several miscellaneous adjustments. Among the miscellaneous adjustments were the test-year wind termination payment of $7.5 million paid to a vendor to terminate a wind construction project, executive expense reports, and other items that are non-recurring or that should be booked below the line. Additionally, KCPL identified the effects of an error in the Massachusetts formula. The Massachusetts formula is used to allocate expenses between operating units and the holding company, namely KCPL, GMO, and GPE, respectively. Staff has included the effects of KCPL’s change in the Massachusetts formula with the exclusion of labor. Staff’s payroll adjustment sufficiently captures the correct allocation of costs between KCPL, GMO, and GPE. Adjustments E-14.3, E-37-2, E-63.2, E-79.2, E-84.2, E-114.2, E-133.4, E-1141.1, E-142.2, E-146.2, E-161.3, E-163.2, E-168.1, E-172.11, E-179.1, E-180.2, E-181.2, E-189.3, and E-189.4 to the Income Statement account for the above miscellaneous expenses in the cost of service.

*Staff Expert/Witness: Keith A. Majors*

## 12. Advanced Coal Credit Arbitration Costs

In 2009, KCPL was served a notice to arbitrate by The Empire District Electric Company (Empire) and the remaining joint owners of Iatan Unit 2, Kansas Electric Cooperative, Inc. (KEPCO) and Missouri Joint Municipal Electric Utility Commission (MJMEUC). The joint owners contended that they were entitled to receive proportionate shares (or the monetary equivalent) of the $125 million advance coal project credit for Iatan Unit 2. In November 2009 this matter was heard by a three person arbitration panel. On December 30, 2009, the arbitration panel, convened pursuant to Article XII of the Iatan Unit 2 And Common Facilities Ownership Agreement, unanimously issued a decision ordering KCPL and Empire to jointly seek a reallocation of the tax credit giving Empire its representative share of the total tax credit worth approximately $17.7 million to Empire. The following are excerpts from the arbitration decision:

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(Emphasis added).

It would appear that KCPL violated the Fair Dealing section, page 6, of the October 30, 2007 GPE Code of Ethical Business Conduct. The Fair Dealing section, page 6, of the October 30, 2007 GPE Code of Ethical Business Conduct provides as follows:

> <u>Business Conduct:</u> **Fair Dealing**
>
> We will deal fairly with the Company's customers, suppliers, competitors and other persons. We will not take unfair advantage of anyone through manipulation, concealment, abuse of privileged information, misrepresentation of material facts or any other unfair-dealing practice.

According to KCPL's response to Staff Data Request No. 720, Case No. ER-2009-0089, the total amount of costs KCPL incurred for the aforementioned arbitration through August 2009 is $41,764. Staff has discovery pending to update this amount through 2009. Staff proposes to remove this amount from the cost of service as Adjustment Number E-167.1. Staff will update this amount in the true-up for all costs incurred through 2009.

*Staff Expert/Witness: Keith A. Majors*

## 13. Iatan Unit 1 Turbine Trip Additional AFUDC removed in Staff's Construction Audit and Prudence Review

In Staff's "Construction Audit and Prudence Review" of the Iatan Construction Project dated November 3, 2010, Staff captured the additional Allowance for Funds used During Construction ("AFUDC") due to the Iatan Unit 1 turbine start-up failure.

For regulated utility companies the AFUDC is the non-cash cost of financing particular construction projects. During construction and prior to the plant providing utility service, this finance cost is capitalized to the construction work order in the same manner as other construction costs such as labor and materials. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) identifies under Electric Plant Instructions, paragraph 17, that AFUDC:

> includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

The Commission's rule on the USOA for electric utilities states, in part, as follows:

> 4 CSR 240-20.030 Uniform System of Accounts-Electrical Corporations Purpose: This rule directs electrical corporations within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major electric utilities and licensees, as modified herein. . . .
>
> (4) In prescribing this system of accounts, the commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.
>
> (5) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

On February 4, 2009, the Iatan Unit 1 turbine tripped during start-up activities due to vibration in the turbine that was beyond its operating parameters. This event occurred following the replacement of the high pressure turbine by KCPL's contractor General Electric ("GE"). The turbine replacement and costs associated with the turbine incident were not within the scope of the Iatan Unit 1 AQCS project and are similar to other capitalized maintenance costs. The unit was repaired and returned to availability for in-service testing on March 9, 2009. The 33 day delay of the unit's ability to perform in-service testing increased the amount of AFUDC accrued on the balance of Iatan Unit 1 plant in construction as the Iatan Unit 1 AQCS could not be declared in-service until April 19, 2009. Staff proposed to remove the incremental AFUDC accrued from the Iatan Unit 1 AQCS project and charge it to the work order that captured the costs for the turbine trip.

On July 7, 2009, Staff filed its "Motion to Open Incident Investigation Case" requesting the Commission to open a case for the purpose of receiving an Incident Report pertaining to Staff's investigation of the February 4, 2009 incident at Unit 1 of the Iatan Generating Station. In "Staff's Incident Report" dated January 29, 2010 in Case No. ES-2010-0009, Staff states that:

> It is not the purpose of this report to make any determination regarding the prudence or imprudence of the actions of KCPL or GE with respect to this incident.

Although Staff made no determination of the prudence of KCPL's actions concerning the February 4, 2009 incident in Case No. ES-2010-0009, KCPL's response to Staff Data Request No. 721 in Case No. ER-2009-0089 suggests that both KCPL and GE had some responsibility for the incident:

> ** ______________________________________________
> ______________________________________________
> ______________________________________________
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To Staff's knowledge, KCPL did not pursue recovery from GE of the additional financing costs incurred because of the turbine trip. Based on the excerpt from KCPL's response to Staff Data Request No. 721 above, it appears KCPL accepted approximately 50% of the responsibility for the rotor incident. The total amount of additional AFUDC accrued on KCPL's portion of the Iatan Unit 1 AQCS project due to the delay caused by the rotor incident was ** __________ **. GE took responsibility for half the costs of the turbine trip, yet KCPL did not pursue GE for the additional AFUDC costs incurred due to the rotor incident.

Staff has made no adjustment to the actual costs of the turbine incident or the consequent repair and return to service of the turbine. However, given the apparent responsibility of both KCPL and GE, Staff sees no reason to include in the Iatan Unit 1 plant balance the proposed transferred amount of AFUDC proposed in Staff's "Construction Audit and Prudence Review" in the work order capturing the costs of the turbine incident. The AFUDC represents KCPL's carrying cost and profit directly attributable to the turbine trip. KCPL will make a recovery of and on the capitalized costs of the turbine incident but should not also receive the incremental AFUDC caused by the turbine incident.

*Staff Expert/Witness: Keith A. Majors*

## 14. Demand-Side Management Cost Recovery

From 2005 to 2008, the Company implemented a series of demand-side programs as part of its Experimental Regulatory Plan (Regulatory Plan) approved on July 28, 2005, in File No. EO-2005-0329. The Regulatory Plan established a Customer Programs Advisory Group (CPAG) to include Staff, Public Counsel, Missouri Department of Natural Resources and other interested parties to serve as an advisory group to the Company in the development, implementation, monitoring and evaluation of the Company's demand response, energy efficiency and affordability programs. On September 15, 2010, Staff provided to the Commission a Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives (File No. AO-2011-0035). Attached to this Staff Report as Appendix 3, Schedule JAR-1 are pages from the Status Report, which highlight the CPAG process and the challenges and successes to date of the Company's demand-side programs.

The Company's overall spending levels for demand-side programs have met and exceeded the expectations established in the Regulatory Plan. As reported by the Company, through June 30, 2010 the budget for all Company demand-side programs is $24,001,009 and the actual total expenditures through this period are $27,442,517, or 14% greater than budget. The energy and capacity impacts and the overall delivery processes of the programs are still being evaluated, measured and verified by a third-party contractor of the Company and will be provided to CPAG members along with copies of completed program evaluation reports. The results of future evaluation reports are not expected to impact this case (also see the **Demand-Side Management** section and the **Demand-Side Management Prudence** section of this Staff Report).

However, the Company formally advised the Commission on February 3, 2010 (File No. EE-2008-0034) that it has determined that "it is appropriate to scale back its demand-side programs in the earlier years of its adopted preferred resource plan due to a reduction in the Company's load forecast, primarily attributable to the unprecedented economic recession that has affected both customer growth and energy and demand growth in the Company's service territory." This "scale back" applies only to the new demand-side programs that were chosen as resources in the Company's most recent Chapter 22 Electric Utility Resource Planning compliance filing, but does not impact the current energy efficiency and demand response programs established in the Regulatory Plan. It is Staff's understanding that KCPL is not accepting new applications for its large customer MPower demand-response program. It is Staff's understanding that KCPL intends to continue offering services of the energy efficiency Regulatory Plan programs to meet customer demand for these programs. Staff and other parties continue to be engaged with the Company as part of the CPAG process to provide advice on the Company's demand-side programs and as a stakeholder to monitor the progress of the Company's Chapter 22 Electric Utility Resource Planning process.

The Regulatory Plan on page 49 also specifies:

> KCPL will accumulate the Demand Response, Efficiency and Affordability Program cost in regulatory asset accounts as the costs are incurred. Beginning with the 2006 Rate Filing, KCPL will begin amortizing the accumulated costs over a ten (10) year period. KCPL will continue to place the Demand Response, Efficiency and Affordability Program costs in the regulatory asset account, and cost for each vintage subsequent to the 2006 Rate Filing will be amortized over a ten (10) year period. Signatories Parties reserve the right to establish a fixed amortization amount in any KCPL rate case prior to June 1, 2010. The amount accumulated in these regulatory asset accounts shall be allowed to earn a return not greater than KCPL's AFUDC rate. The class allocation of costs will be determined when the amortizations are approved.

The direct testimony of Company witness Tim M. Rush in this general rate proceeding includes a request for continuation of the current regulatory asset accounts and amortization over ten years of costs related to the Company's demand response, energy efficiency and affordability programs. Staff is in support of this request (see the **Demand-Side Management** section of this Staff Report).

The "Missouri Energy Efficiency Investment Act" (MEEIA) was established in Senate Bill 376 and became law on August 28, 2009. During 2009 and 2010, Staff organized a stakeholder process including a series of workshops to obtain stakeholder input and to promulgate rules in compliance with MEEIA (File No. EW-2010-0265). Staff subsequently filed proposed MEEIA rules with the Commission in File No. EX-2010-0368. On October 4, 2010, the Commission sent the proposed MEEIA rules to the Office of the Secretary of State. It is anticipated that the proposed MEEIA rules will be published in the *Missouri Register* on November 15, 2010, and the Commission has scheduled a hearing regarding the proposed MEEIA rules for December 20, 2010.

Staff has evaluated the typical timeline for rulemakings established in Chapter 536, RSMo, and concludes that a final order of rulemaking for the MEEIA rules can be reasonably expected so that MEEIA rules will first be effective near June 2011, which is after the May 4, 2011 requested effective date of the Company's new tariffs in this general rate proceeding. It is highly unlikely that MEEIA rules will be effective prior to the effective date of new tariffs in this general rate proceeding. Staff, therefore, believes effective MEEIA rules can have no direct impact on the outcome of this general rate proceeding.

However, with the passage of Senate Bill 376 and the enactment of MEEIA, the State of Missouri has declared and directed the following:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that

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

While Staff does not view the Company's existing demand-side programs presently to be demand-side programs proposed pursuant to section 393.1075.4 RSMo. Supp. 2009, the current regulatory asset treatment of the Company's demand-side costs as discussed in this section and in the **Demand-Side Programs** section of this Staff Report should be continued until the Commission has rules in effect to implement MEEIA.

*Staff Expert/Witness: John A. Rogers*

## 15. Demand-Side Management Prudence

The Demand-Side Management (DSM) Account 182440 contains costs that have been incurred for fourteen (14) DSM programs[36] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and

[36] DSM programs consist of demand response, energy efficiency and affordability programs, including the low income weatherization programs.

(2) DSM market research costs. At this time, Staff has no recommended disallowances to the levels of costs charged to KCPL's DSM Account.

As part of the KCPL Experimental Regulatory Plan (Case No. EO-2005-0329), the Customer Program Advisory Group (CPAG) was ordered to include Staff, Public Counsel, Department of Natural Resources and other interested parties to advise KCPL on the development, implementation, monitoring and evaluation of demand response, energy efficiency and affordability programs. Based on Staff's participation in the CPAG and Staff's review of the costs in Account 182440, Staff discovered no evidence of imprudence regarding the level of costs charged to the DSM programs.

The DSM program costs include the payments to KCPL's customers that participate in the MPower Program. The MPower Program is a commercial and industrial load curtailment program. This program allows KCPL to call for curtailment for emergency and for economic reasons. Staff is allowing the level of costs charged to this program to be included in the DSM account because the revenues from such sales on the wholesale market will be returned to the retail customers through a mechanism established by the Commission in a previous KCPL rate case, File No. ER-2006-0314.

*Staff Expert/Witness: Hojong Kang*

## <u>16. DSM Costs</u>

The DSM Account 182.440 contains costs that have been incurred for fourteen (14) DSM programs[37] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and (2) DSM market research costs. At this time, Staff has no adjustments to the DSM Account.

[37] DSM programs include demand response and energy efficiency programs, including the low income weatherization programs.

Based on Staff's participation in the Customer Program Advisory Group, established to advise KCPL in the development of DSM programs, and Staff's review of the costs in Account 182.440, Staff has treated the previously mentioned amounts according to the amortization process agreed to in the KCPL Regulatory Plan Stipulation and Agreement, entered into in Case No. EO-2005-0329. The Stipulation and Agreement allows KCPL to capitalize a financial return on the project expenses deferred in the DSM regulatory asset account. The Stipulation and Agreement prohibits this return from being higher that KCPL's Allowance For Funds Used During Construction (AFUDC) rate.

In its direct filing the Staff removed KCPL's test year DSM amortizations (Adjustments E-144.2 through E-144.4) and included its recommended level calculated in a manner consistent with its treatment in Case No. ER-2009-0089.

In Case No. ER-2009-0089, the balance of Vintage 3 DSM deferral was adjusted to reflect the Missouri jurisdictional portion of the Surface Transportation Board complaint case refunds, the amount of KCPL's 2007 and 2008 off-system sales margin in excess of the amount directly included in rates in the ER-2007-0291 case, and the transfer of certain DSM related advertising costs charged to KCPL's income statement advertising accounts. These DSM deferral adjustments were agreed to as to amount and were reflected in the Non-Unanimous Stipulation and Agreement to Case No. ER-2009-0089 as reflected below:

> <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.

Surface Transportation Board ("STB") Litigation

The Signatory Parties agree that 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 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.

Deferred DSM Advertising Costs

The Signatory Parties agree that $279,521 (Missouri jurisdictional) of 2007 advertising costs will be deferred in a regulatory asset account and amortized over ten years beginning with the date new rates become effective in this rate case, with one-tenth of this cost included in cost of service in this case. The unamortized balance will not be Included in rate base as agreed to in the 2005 Stipulation.

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. The Staff and KCPL agreed that KCPL should defer all costs of prosecuting this case against UPRR and that if KCPL won the case, the settlement and refunds would be returned to KCPL's ratepayers who paid the overcharges. In KCPL's last rate case, Case No. ER-2009-0089, the Staff and KCPL agreed that at the time of that rate case, the appropriate Missouri jurisdictional refunds were $1,017,593. In discussions with KCPL in this case, KCPL has indicated that no additional refunds have been received from UPRR.

In its direct filing in this case, File No. ER-2010-0355, the Staff netted KCPL's ER-2009-0089 off-system sales margin in excess of the amount directly included in rates in the ER-2009-0089 case in DSM Vintage 4, the level of KCPL's DSM deferrals from October 2008 through June 30, 2010.

In Staff Adjustments E-144.5 through E-144.8 Staff included annual amortizations (10-year deferral period) for the following DSM vintage deferrals:

| DSM deferral | Case No. | Amount |
|---|---|---|
| Vintage 1 | ER-2006-0314 | $ 239,666 |
| Vintage 2 | ER-2007-0291 | $ 448,624 |
| Vintage 3 | ER-2009-0089 | $ 193,663 |
| Vintage 4 | ER-2010-0355 | $1,136,996 |

In addition to the approximately $2 million of DSM amortizations, in Adjustments E-144.9 through E-144.12, to KCPL account 908, Amortization of Deferred DSM 100% MO, the Staff included the AFUDC return on the unamortized DSM balances. At June 30, 2010, the total unamortized balances of DSM Vintage 1 through 4 was $17.9 million. The AFUDC rate Staff applied to this unamortized DSM balance was 6.63% and is KCPL's June 2010 AFUDC rate as reflected in KCPL's response to Staff Data Request No. 623 in Case No. EO-2010-0259. The AFUDC return amount totals approximately $1.2 million for a total increase in revenue requirement from DSM deferrals of approximately $3.2 million.

*Staff Experts/Witnesses: Hojong Kang and Charles R. Hyneman*

## 17. Interest On Off-System Sales Margin

In Case No. EO-2005-0329, the Commission approved a Stipulation and Agreement that contemplated an Experimental Alternative Regulatory Plan. Under the terms of the Stipulation and Agreement, KCPL agreed that off-system energy and capacity sales revenues, and related costs, will continue to be treated "above the line" for ratemaking purposes. 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, 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. The Commission ordered a continuation of this method of accounting for off-system sales in KCPL's two subsequent general rate cases, Case Nos. ER-2007-0291 and ER-2009-0089.

In KCPL's last rate case, Case No. ER-2009-0089, instead of setting up a separate deferral and amortization tracker for the deferral and amortization of this cost of service item, Staff netted the annual Missouri jurisdictional excess off-system sales margins for ER-2006-0314 ($1,082,974) and ER-2007-0291 ($2,947,332) against KCPL's DSM regulatory asset deferral. Staff is proposing to continue this rate treatment in this case. In its direct revenue requirement filing in this case, the Staff has offset (reduced) KCPL's most recent DSM deferral (Vintage 4 deferral October 2008 through June 2010) by the excess off-system sales margins for Case No. ER-2009-0089. The Staff will update the ER-2009-0089 excess off-system sales margin tracker in its true-up filing in this rate case. The Case No. ER-2009-0089 tracker amount of $3,165,549 was calculated based on the off-system sales data provided by KCPL in response to Staff Data Request No. 464. As noted in the Stipulation and Agreement language below, the calculation of the monthly excess off-system sales margins will be based on the off-systems sales results from 2008. Due to the test-year update month ending in June 2010, only ten months of actual excess off-system sales margins are included in the Staff's direct filing. This Staff's calculation is as follows:

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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.



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The Signatory Parties reserve the right to assert a position regarding the appropriate definition of OSS in the Company's next general rate case.

*Staff Expert/Witness: Charles R. Hyneman*

## 18. Low Income Programs

### a. Economic Relief Pilot Program

Kansas City Power and Light Company's (KCP&L or Company) Economic Relief Pilot Program (ERPP) began September 1, 2009. It was approved by the Commission in ER-2009-0089 as a three (3) year pilot program. It is designed to study the ability to create an energy credit benefit to KCPL's qualifying low-income residential customers. The ERPP was designed to pay up to fifty dollars per month to low-income customer's in the form of a "fixed credit" that would appear on the participants current bill. The purpose of the "fixed credit" applied monthly would be an attempt to make the bill more affordable for the customer with the hope that the customer would remain current on their electric utility bill. The tariff also stated that an evaluation of ERPP may be in any Company rate or complaint case and that the evaluation shall be by an independent third party evaluator under contract with the company that would be acceptable to the Company, Commission Staff and the Public Counsel. In addition, the ERPP pilot Agreement allowed KCPL to defer fifty percent of the cost of the program until KCPL's next rate case.

*Staff Expert/Witness: Carol Gay Fred*

#### 1. Recommendation

Based on Staff's review of KCPL's witness Jimmy Alberts testimony and the data responses received by OPC, Staff would recommend the continuation of the ERPP program for the life of the pilot program but strongly recommends that the company acquire an independent third party evaluator of the program. Until this task is accomplished, the Staff recommends not allowing the company to recover fifty percent of the cost of the program at this time. Staff bases this recommendation on three points:

1. In the initial design of ERPP, was to include one thousand customers from KCPL territory and one thousand from GMO territory. However, as of June 2010 KCPL had enrolled only five hundred and twenty-six (526) KCPL customers and four hundred and seventy-four (474) GMO customers. Staff recognizes that the program only began September 1, 2009, however, nine months later or three quarters of the year from the start-up of the pilot program KCPL and GMO collectively, have only one thousand out of the anticipated two thousand participants enrolled in the program. This does not appear to be sufficient to request cost recovery of deferred cost created by the customers enrolled.

2. The company has not acquired a third party evaluation study on the program to verify the information or calculation used in this case.

3. In addition, in prior Staff witness Anne E. Ross' Rebuttal Testimony in Case No. ER-2009-0089, she stated, "Staff believes that a third party evaluation studying the effect of the program on the Company's bad debt level should be a condition of the Company recovering any program funds in future rate or complaint case proceedings. Due to the necessity of collecting adequate pre-and post-program usage information on participants, it may not be possible to evaluate the program in the next rate or complaint proceeding, in which case the decision as to whether the Company would be allowed to recover these deferred expenses should be delayed until a program evaluation is performed."

The Commission should allow the continuation of the ERPP for the full three (3) year life of the program; however, Staff makes the following additional recommendations:

- Acquire an independent third party evaluator for the program to track all aspects of the program for weaknesses, strengths and improvement opportunities.
- Work more extensively with Salvation Army to ensure capacity enrollment of ERPP.
- Improve on education and providing awareness of ERPP with other Energy Assistance Agencies of the availability of ERPP, i.e., United Services Community Action Agency, 211, St. Vincent de Paul, etc.
- Provide SA field staff availability to AgencyLink, the web based interface that allows registered social service agencies access to restricted and highly limited view of customer information in order to assess account status and only the information required to make a determination to qualify customers for ERPP and other agency payments.
- Continue to conduct as many as feasible Connections campaign Energy Resource Fairs on an annual basis.

*Staff Expert/Witness: Carol Gay Fred*

### 2. Qualifying Criteria

The program was designed to help residential low-income customers whose annual household income is no more than 185% Federal Poverty Level (FPL) as established by the poverty guidelines updated periodically in the Federal Register by the U.S. Department of Health and Human Services under the authority of 42 U.S.C. 9902 (2).

- Participants account must be current or those who have an outstanding arrearage must enter into a special payment arrangement as mutually agreed to by both Participant and Company.

- Participants must have not current or historical mishandling of their account, i.e., tampering, non-payment or diversion.

- Participants must complete an interview or questionnaire, of information related to their energy use and program participation.

- Participants will not be subject to late payment penalties while participating in the program.

- Participants must apply for Low-Income Energy Assistance Program (LIHEAP) grant and any other energy assistance programs identified by the Company.

*Staff Expert/Witness: Carol Gay Fred*

### 3. Credits

Participants shall receive the available ERPP credit as long as the participant continues to meet the ERPP eligibility requirement and reapplies to the program annually.

The credit amount is not to exceed \$50 per month. The credit amount will be determined by the Company the time of enrollment.

*Staff Expert/Witness: Carol Gay Fred*

### 4. Arrearages

Participant will enter special pay agreements as mutually agreed to by both the Participant and the Company.

*Staff Expert/Witness: Carol Gay Fred*

### 5. Billing Periods

The credit will appear on each monthly bill, enabling the Participant can see the savings to his account and any arrearage elimination once accomplished.

*Staff Expert/Witness: Carol Gay Fred*

### 6. Education

Education for the ERPP program as well as other options available to the consumers is part of an education and outreach campaign called “Connections”. It appears the “Connections” program was designed to be an education outreach program to provide customers a local presence in the communities where they live as a one-stop-shop, direct face-to-face interaction, allowing an opportunity to discuss account specific questions and solutions. It was also seen as a way to partner with other community organizations, i.e, Salvation Army, United Way 2-1-1, and KCMO Weatherization initiative. Through this program, KCP&L also hosts Connections Energy Resource Fairs, Back to School Fairs, etc. There is also an exclusive 800-number during the Connections campaign to support customers unable to attend a local program.

*Staff Expert/Witness: Carol Gay Fred*

### 7. Program Administration

KCPL contracted with the Salvation Army as their partnering agency who has an established presence in the community, to act as the gatekeeper. The Salvation Army processes the ERPP applications, however, KCPL reviews the applications submitted by the Salvation Army to determine if the applicant meets all criteria to be a program participant. It appears there are two primary barriers to the initial participation; 1) marketing to customers and 2) communications methodology with SA, specifically to SA outlying field offices.

*Staff Expert/Witness: Carol Gay Fred*

**b. Low-income Weatherizaton**

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

The federal government, through the American Recovery and Reinvestment Act (ARRA) is providing special funding of $128 million for the Missouri Weatherization Program for the period of April 2009 – March 2012 (ARRA Period). The ARRA provides an average of $6,500 of weatherization for households with income at 200% or less of the Federal Policy Guidelines. In the previous three year period (2006 2008), prior to the ARRA Period, federal funding for the Missouri Weatherization Program was approximately $18 million and the average amount of weatherization per household was $3,000. The amount of weatherization has increased has increased from about $3,000 to $6,500 per household. The Weatherization Agencies are making a concerted effort to utilize the ARRA funding before the March 2012 deadline.

The Commission Order authorized the KCPL Regulatory Plan (Regulatory Plan) in the Stipulation and Agreement in Case No. EO 2005 0329. In this Plan, KCPL agreed to contribute $573,888 in 2010 to weatherization agencies for the weatherization of qualifying customers ($550,000 for KCHCDD, and $23,888 for MVCAA and CMCA). The last year of funding in the Regulatory Plan is 2010. According to an August 31, 2010, Regulatory Plan, Customer Program Expenditures spreadsheet furnished to the Customer Program Advisory Group (CPAG), attached as Appendix 4, Schedule 1, KCHCDD, MVCAA, and CMCA have used ** ____ ** of the Regulatory Plan budgeted funds for weatherization. This under-utilization of funds is primarily because of the agencies' focus on using the ARRA funding and restrictions on ARRA funds being combined with utility funds. At the end of the ARRA period the Weatherization Agencies anticipate using any surplus utility funds to maintain their level of weatherization activity.

The Missouri State Environmental Improvement and Energy Resources Authority (EIERA) was established to manage and disburse federal and other weatherization funds for MDNR to the Weatherization Agencies according to MDNR guidelines. Currently four other Missouri jurisdictional utilities utilize the EIERA to manage their weatherization funds. The funds at the EIERA are invested to earn a return until they are distributed so the value of the funds is enhanced.

Staff recommends that the unutilized low-income weatherization funds from the Regulatory Plan be placed in an account with EIERA. In addition, in order have some additional KCPL funds for weatherization when the ARRA funds are no longer available, Staff recommends that KCPL continue to provide annual funding of $573,888 for low income weatherization, as currently allocated between KCHCDD, MVCAA, and CMCA. Staff also recommends that KCPL change its distribution method for the weatherization funds from monthly direct reimbursement to the Weatherization Agencies to an annual deposit of the funds to an EIERA account.

*Staff Expert/Witness: Henry E. Warren*

### 19. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability 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 pre-paid by utilities; i.e., payment is made by the utility 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.

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

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess fiduciary
- Workman's Compensation

- Excess Workman's Compensation
- Property
- 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 to the GMO entities and reflected in those entities cost of service (File No. ER-2010-0356). Adjustments E-171.1 and E-170.1 reflects the annualized levels for KCPL's portion of the insurance costs.

*Staff Expert/Witness: Karen Lyons*

### 20. Injuries and Damages

Injuries and damages relate to insurance claims that are not covered by insurance policies. Injuries and damages usually consist of claims associated with general liability, workman's compensation, and auto liability. The Commission ruled in Case No. ER-2006-0314, that the accrual method of accounting should be used when calculating the costs associated with injuries and damages. Staff believes the accrual method is not an accurate method to use to determine the appropriate costs associated with injuries and damages. The accrual method is an estimate of what the Company may pay for future claims, but these claims are not actually known. As such, the estimates do not meet the criteria of known and measurable costs used in the ratemaking process. Staff analyzed five years of data and determined a three-year average, including the period of 2007 through 2009, using the actual cash payments to normalize the Company's costs associated with injuries and damages. The actual cash payments are those paid to individuals who had an injury and claim. As a result of these injuries, KCPL made cash settlements. A three year average was used based on the data received from the Company. Adjustment E-171.3 reflects a normalized level of costs for injuries and damages.

*Staff Expert/Witness: Karen Lyons*

### 21. Rate Case Expense

Rate case expenses are costs incurred by a utility in preparation and performance of its filing for a rate case. In the instant case, KCPL has incurred expenses in conjunction with legal counsel, regulatory consulting and outside consultants.

Staff usually treats rate case expense as a normalized expense necessary to provide utility service. This treatment involves determining the cost to process a rate case on a normalized level and reflecting that cost in the cost of service over the period of time between rate cases. However, because of KCPL's Regulatory Plan developed as a result of its Comprehensive Energy Plan (CEP), and the resulting recurring rate case filings, Staff has not taken issue with KCPL's proposed ratemaking treatment of rate case expense. Starting with Case No. ER-2006-0314, Staff has agreed to use a "defer and amortize" or "vintage accounting" approach for KCPL's rate case expense, in contrast with Staff's traditional normalized cost approach.

Under this special defer and amortize approach to rate case expense, KCPL defers the rate case expenses for each rate case as a separate vintage deferral and amortizes each of those vintage deferrals over a two year period. The rate case KCPL incurred after the end of the true-up period in one case is transferred to the next rate case to be recovered in the rates established in that case. Staff is proposing to continue with the defer and amortize method for rate case expense in this last of KCPL's Regulatory Plan rate cases. The Staff expects to return to the expense normalization approach in future KCPL rate cases.

In the "Non-Unanimous Stipulation and Agreement" approved by the Commission in Case No. ER-2009-0089, the Signatory Parties agreed that any over-recovery of the amortization of the Company's rate case expense in Case No. ER-2006-0314 will be used to offset the amount of rate case expenses incurred and deferred in Case No. ER-2009-0089. This application of over recovered expenses, while not an approach that would be used under normal ratemaking circumstances, is consistent with the defer and amortize or rate case tracker accounting used in KCPL's Regulatory Plan rate cases. Staff has continued with this rate case tracker approach and applied the over recovery of rate case expense from Case No. ER-2007-0291 against KCPL's rate case expense deferral in this rate case.

Staff reviewed the Company response to the request for invoices for rate case expenses incurred for the current case. Staff accumulated the amount of invoices paid by KCPL to vendors related to the Iatan Project prudence review and construction audit. In examination of the invoices, significant amounts of invoices for legal expenses and consulting expenses did not include hours billed, the nature of the services provided, and any expenses billed. These invoices only included the front sheet of the invoice listing the total billed and an expense distribution. Staff cannot determine the reasonableness and prudence of the expenses paid on the invoices. Staff currently has a pending data request to receive the complete copies of the invoices with receipts for expenses. Staff has removed these invoices in the rate case expense amortization calculation and proposes that the prudent and reasonable expenses related to the Iatan Project prudence review and construction audit be capitalized to the applicable Iatan 1 and 2 plant balances. Staff will include the prudent and reasonable costs in its true-up of Iatan Project costs through October 31, 2010. In addition, Staff will include all prudent and reasonable costs incurred and paid through the true-up of the current rate case, File No. ER-2010-0355.

Staff Adjustment E-179.5 reflects an amount for rate case expense to be recovered over a two-year period for Case No. ER-2009-0089, net of the adjustment for the over-recovery from the amortization of rate case expense from Case No. ER-2006-0314. The total amount of this adjustment is $276,031.

Staff Adjustment E-179.6 reflects an amount for rate case expense to be recovered over a two-year period for the prudent and reasonable costs incurred by KCPL to process the current rate case, File No. ER-2010-0355 before the Commission and, as noted above, applied the over recovery of rate case expense in Case No. ER-2007-0291 against this deferral. The total amount of this adjustment is $539,605.

*Staff Expert/Witness: Keith A. Majors*

## 22. Public Service Assessment Fee/FERC Assessment Fee

The Public Service Commission assessments (PSC Assessment) over 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. The PSC Assessment is charged to regulated utilities operating in Missouri. KCPL's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2011) 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 to form the basis for the adjustment in Staff's cost of service run. Staff also chose to update the Company FERC Assessment paid to represent 12 months ending June 30, 2010. FERC is the Federal Energy Regulatory Commission, and they have a separate assessment to be paid by all regulated utilities, handled in similar fashion to the aforementioned PSC Assessment. Adjustment E-178.1 and FERC-E-175.1

*Staff Expert/Witness: Bret G. Prenger*

## <u>23. Transmission Expenses Tracker</u>

The full transfer of control of the Company's transmission system to participate in all functions of the Southwest Power Pool (SPP) regional transmission organization was finalized on October 1, 2006. On this date, the Federal Energy Regulatory Commission's (FERC) order accepting the "Agreement for the Provision of Transmission Service to Missouri Bundled Retail Load" was effective, allowing the Company to exercise the authority granted to it by the Missouri Public Service Commission (Commission) in Case No. EO-2006-0142.

The Company's historic transmission expenses are provided on Schedule TMR2010-5 of Company witness Tim M. Rush. Schedule TMR2010-5 also includes the Company's estimated amount of its 12-month ending December 31, 2010 transmission expenses that it included in its filing that initiated this case. That estimated transmission expenses amount includes estimated transmission expenses for July through December 2010 and three adjustments described in the testimony of Company witness John P. Weisensee from line 16 on page 50 to line 19 on page 51 and from line 2 on page 62 to line 19 on page 63. Staff has summarized those Company adjustments as follows:

- Adjustment CS-45: Annualized expected transmission costs in FERC account 565 based on: 1) expected increased transmission expenses primarily due to increased off-system sales made possible by Iatan Unit 2, and 2) projected costs related to SPP base plan upgrades to meet the mandatory North American Electric Reliability Corporation and SPP reliability standards, which call for one-third of each base plan project to be shared by all SPP members and the remaining two-thirds of the project cost to be allocated among the members that directly benefit from the project.
- Adjustment CS-85: Annualized Missouri regulatory assessments and FERC Schedule 12 fees based on assessment levels projected to be in effect in December 2010. Under this new procedure, FERC will begin to base its assessment on all load under SPP rates including retail load served by member companies and will bill SPP for the assessment. SPP will then pass a share of this cost through to all point-to-point and network service customers it serves.

- Adjustment CS-86: Annualized SPP Schedule 1-A fees based on the annual funding levels expected to be in effect on December 31, 2010 and on the Company's share of load at the time of the twelve monthly system peaks. The Schedule 1-A fees are for SPP activities related to regional transmission planning, processing and studying transmission and generation interconnection service requests, managing congestion across the transmission system, administering the SPP transmission tariff, serving as a reliability coordinator, managing the power reserve sharing system and operating the regional energy imbalance market.

The annual amounts of the Company's historic and estimated test year transmission expenses the Company provides in its filing that opened this case are:

**Transmission Expenses [38]**

| ($000) | | | | | |
|---|---|---|---|---|---|
| **2005** | **2006** | **2007** | **2008** | **2009** | **Est. 2010** |
| $3,100 | $7,864 | $15,001 | $17,343 | $18,518 | $25,054 |

Staff has completed its review of the Company's transmission expenses and recommends the Commission authorize the Company to use a transmission expense and revenue tracker. Staff recommends the Company be authorized to use a transmission expense tracker due to the historical growth in and current high level of the Company's transmission expenses, the uncertainty in the levels of its future transmission expenses, and because the Company has less control over the level of transmission expenses the SPP assigns to it than the Company has over most of its other expenses. Staff does assert that the Company has control over the transmission expenses it incurs related to transmission it, or its affiliates, directly constructs.

The uncertainty of the Company's future transmission expenses is increased by the recently FERC approved "Highway Byway" cost allocation tariff filing, which will increase the percentage of costs of newly planned transmission throughout the SPP region that will be

[38] Including FERC Account Numbers 561400, 561800, 565000, 565020, 565021, 565027, 565030, 575000 and 928003. Note that Staff has proposed a different transmission tracker amount.

allocated to the Company. For example, the Company will be allocated approximately 7.5% of all transmission planned in the SPP footprint above 300 kilo-Volt (kV).

SPP has also approved a higher level of transmissions expenses than normal in the recent past, and Staff expects this trend to continue. For example, in April 2010, SPP approved $1.4 billion of transmission expenses in its “Priority Projects.” Staff does expect additional transmission valued at over $1 billion to be planned by SPP in its new Integrated Transmission Planning Year 20 (“ITP20”), consisting of transmission at, or possibly about, 345 kV, which is most likely to be voted on for approval by the SPP Board in January 2011. Approval of ITP20 would lead to an increase in expected future transmission expenses for the Company, although the exact amount of those expenses are unknown at this time. Transmission project cost estimates may also differ significantly from the final cost of these projects built, increasing the uncertainty of the future level of the Company’s transmission expenses.

While KCPL may have less control over expenses assigned to it by SPP than other expenses it incurs, Staff expects and encourages KCPL to work within the SPP stakeholder process to advocate for transmission improvements that benefit KCPL stockholders and KCPL ratepayers, and to advocate for a proper allocation of transmission expenses. Staff notes that KCPL does currently have a voice on the Members Committee of SPP through its representative, Michael L. Deggendorf, KCPL’s Senior Vice President-Delivery.

In those situations where the Company has direct control over the transmission expenses it incurs, Staff recommends the Commission require KCPL to file with the Commission the information shown in Appendix 5, Schedule DIB - 1, and provide that same information to SPP, when KCPL proposes a transmission project at a voltage greater than 100 kV, and that KCPL be required to update that filing each time the project cost estimate changes by more than 10% from the last cost estimate KCPL filed with the Commission within seven days of when the project cost estimate is changed. In addition, Staff recommends the Commission order the Company to file quarterly updates of the costs incurred and progress made towards completion of all transmission projects.

If off-system sales change in this instant case, then there should be a corresponding adjustment to KCPL's transmission expenses included in any transmission expense and revenue tracker related to off-system sales. In prior KCPL rate cases, during the case, the levels of off-system sales proposed have changed dramatically. In the current economic conditions Staff believes this is very likely to happen again in this rate proceeding. Staff will continue to review transmission expenses and proposed off-system sale levels, and propose any appropriate adjustment to transmission expenses based on changes in off-system sales levels.

Staff recommends a transmission expense and revenue tracker include two FERC Accounts included as "revenue credits" in the Company's FERC Transmission formula rate filing in the transmission tracker: FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission); and FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity".. Staff recommends that the revenues from these accounts be used to negatively adjust the amount in FERC Account 565.000.

Worksheet "A-1 Revenue Credits" from the Company's FERC Formula Rate Spreadsheet[39] is attached as Appendix 5, Schedule DIB-2. The relevant account names and totals have been highlighted.

[39] The inclusion of information from the Company's formula rate spreadsheet does not constitute Staff taking a position on the Company's formula rate.

Appendix 5, Schedule DIB-3 lists the differences between the transmission tracker proposed by KCPL in its direct testimony and the proposed amount of Staff's transmission expense and revenue tracker. The proposed amount of Staff's transmission expense and revenue tracker is $17,468,285. The amount of FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity", is listed as Staff Adjustment 1. The amount of FERC Account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) is listed as Staff Adjustment 2.

For fiscal year 2009, FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) is $155,908. For Fiscal Year 2009, the "Net 456.1 Account Activity" is listed at $7,430,144. These totals are for the KCPL total company.

Staff recommends that the transmission expense and credit amounts included in KCPL's revenue requirement for setting rates for this rate proceeding be based on the true-up amount for the 12-months ending December 31, 2010 for (1) the expenses in the accounts listed on Company witness Tim M. Rush's Schedule TMR2010-5; and (2) the revenues in FERC Account 454.0001 (to the extent derived from transmission) and FERC account 456.1 that would be listed in the FERC Formula Filing as "New 456.1 Account Activity".

Like KCPL, Staff proposes KCPL should track its actual transmission expenses on an annual basis. Staff further recommends the revenues from the two Staff Adjustments listed above also be tracked on an annual basis. Also, Staff recommends these expenses and revenues include only Missouri jurisdictional revenues and expenses. Like KCPL, Staff agrees proposes that KCPL record any annual excess amount above the transmission expenses amount included in the revenue requirement used in setting rates in this rate proceeding as a regulatory asset (account 182) and any annual shortfall below the transmission expenses amount in rates in this rate proceeding as a regulatory liability (account 254). Staff recommends the regulatory asset or regulatory liability be amortized over five years in the Company's next rate proceeding, with the unamortized balance included in rate base.

*Staff Expert/Witness: Daniel I. Beck*

## 24. Smart Grid Demonstration Project

The KCPL SmartGrid demonstration project (Project) is included in the Department of Energy (DOE) and Electric Power Research Institute (EPRI) demonstration programs[40] and is physically located in an economically challenged area of Kansas City, Missouri. The Project's expectations are that the Project will deliver benefits to the immediate Project's end-users and provide valuable experience and lessons learned for future applications. It is being promoted as an end-to-end SmartGrid that will include advanced metering infrastructure (AMI), renewable generation, energy storage resources, leading edge substation and distribution automation and control, energy management interfaces, and innovative customer programs to include time of use (TOU) rate structures. Project funding consists of approximately $48.1 million to be spent from 2010 through 2014, of which $13.8 million (29%) is KCPL funded, $10.2 million (21%) is partners/vendors funded and $24.1 million (50%) is federally funded. [41] Teaming with KCPL as vendor partners are Siemens Energy Inc., Open Access Technology, Inc. (OATI), Landis&Gyr AG, Emeter/Siemens, Exergonix, Tendrill, EPRI and Intergraph.[42]

The Project will focus on the area served by KCPL's Midtown Substation across two square miles, impacting about 14,000 commercial and residential customers across ten circuits with total electrical demand of 69.5 MVA. The SmartGrid project includes over 25 stakeholder

[40] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[41] KCP&L Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.
[42] KCP&L Green Impact Zone SmartGrid Demonstration Project Management Plan ,submitted to the DOE, October 29, 2010.

groups including, Mid-America Regional Council (MARC), Metropolitan Energy Center (MEC), Missouri Gas Energy (MGE), University of Missouri at Kansas City (UMKC), Kansas and Missouri Regulatory Agencies, City of Kansas City, Missouri and several local neighborhood groups.[43]

Within the SmartGrid demonstration project boundaries lies the Green Impact Zone project, a 150 square block area of inner-city neighborhoods in Kansas City, with the primary goal of transforming distressed urban neighborhoods into a sustainable community.[44]

The Project will be based upon the guidance found in the proposed National Institute of Standards (NIST) interim Smart Grid Interoperability Standards Roadmap, the EPRI IntelliGrid Achitecture and the GridWise Architectural Council recommendations.[45]

The primary, overall focus for the Project will be to implement next-generation, end-to-end SmartGrid components that will include Distributed Energy Resources (DER), enhanced customer facing technologies, and a distributed-hierarchical grid control system that includes the following key elements:[46]

- Upgrade the Midtown Substation to create a next generation "SmartSubstation;"
- Upgrade multiple distribution circuits with a variety of feeder based instrumentation and control devices for monitoring and control;
- Grid management infrastructure to support the upgraded grid, back office and substation requirements;
- SmartMeters with AMI installed at all customer sites to provide consumers with enhanced information on energy use and the opportunity to utilize residential TOU rate structures with an expected participation level of 426 residential customers; and
- Integration of distributed generation that includes a large battery storage system and distributed roof-top solar photovoltaic systems.

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[43] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[44] KCP&L Green Impact Zone SmartGrid Demonstration Abstract
[45] KCP&L Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.
[46] KCP&L Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009.

Consumers will be offered a wide range of products and services with the following expected level of participation:[47]

- Customer's with internet will have access to real time energy usage;
- 1,600 residential and commercial are expected to have in home/business energy displays and demand response thermostats;
- 400 residential users are expected to utilize a Energy Management System (EMS);
- 2 commercial users are expected to utilize a EMS;
- 10 LED area lights will be installed at UMKC;
- 64 residential users are expected to utilize hyper efficient appliances;
- 5 commercial and 10 residential users are expected to utilize roof-top solar; and
- 10 distributed vehicle charging stations to accommodate Plug in Hybrid Electrical Vehicles (PHEV).

KCPL is proposing to implement this demonstration project in the five following project phases.[48&49]

1. Project Definition and Compliance to refine project scope, definition and ongoing project management; years 2010-2014.
2. Project Design and Performance Baseline compile and/or collect baseline grid and end-use data for the demonstration area; year 2010.
3. Smart Grid Infrastructure Deployment to implement the SmartSubstation, Data Management System (DMS) and Advanced Distribution Automation (ADA) components; years 2011 & 2012.
4. Distributed Energy Resource Deployment to implement the SmartEnd-Use, SmartGeneration (Solar, Battery, PHEV), DER/DR Management components, introduce TOU pilots; Years 2011-2012.
5. Data Collection, Reporting & Project Conclusion operate the integrated SmartGrid demonstration systems, collect 24 months of grid, evaluate system and analyze performance; Years 2013-2014.

In summary, this is an important project for Missouri, since it is the only large scale SmartGrid demonstration project currently planned for Missouri. In addition, because this is an

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[47] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010.
[48] KCP&L Green Impact Zone SmartGrid Demonstration submitted to the DOE, August 26, 2009
[49] Smart Grid Demonstration Project presentation to EEI Strategic Issues Roundtable, October 20, 2010

EPRI and DOE demonstration project, Missouri will receive much exposure. Staff activities to date have consisted of attending presentations, meetings, physical project site reviews, reviewing documentation and proposed tariffs. All Missouri utilities will also benefit from the project data, lessons learned and evaluation of project performance after project completion.

*Staff Expert/Witness: Randy S. Gross*

# VIII. Depreciation

## A. Recommendation

Staff recommends that the Commission order KCPL to:

1. Use the depreciation rates described in Schedule AR-1,
2. Charge current cost of removal and salvage expenses (net salvage) to the accumulated additional amortizations, and
3. Record all plant cost of removal and salvage by FERC account, date, and location unit code in a permanent continuous record, including cost of removal and salvage for production units previously removed from service. Include in this record a differentiation between interim and final retirements and net salvage.

Staff's recommendation results in annual depreciation expense of approximately $85,000,000. Staff recommends reducing the excess accumulated depreciation reserves by approximately $14,000,000 annually. The accumulated depreciation reserve is estimated to have accrued $438,000,000 more than the appropriate reserve balance, as shown in Appendix 6, Schedule AR-2.

Staff's recommended depreciation rates shown in Appendix 6, Schedule AR-1 are based on the following:

1. Treatment of all non-nuclear Steam and Other production, Transmission, and Distribution accounts as living accounts[50], with mass property[51] analysis and whole life[52] depreciation rates.

2. Life span[53] analysis with remaining life[54] depreciation rates for the Nuclear and Hawthorn [5] Rebuild accounts.

3. General plant accounts 391, 393, 394, 395, 397, and 398[55] have been left at the current ordered rates, pending identification by KCPL of retirements associated with recent office consolidations and relocations.

4. Net Salvage[56] has been set to zero for all plant accounts. Accounting for current net salvage has been transferred to a separate regulatory account. Collection of future cost of removal has been temporarily suspended to compensate for an estimated 52% over accrual in total plant depreciation reserves. The estimation of over accrual in reserves is shown in Appendix 6, Schedule AR-2

## B. Regulatory Depreciation

Staff's recommended rates are based on KCPL's past plant retirement history, with influence from retirement histories of similar utility companies and future plant operation expectations. Staff's objective in recommending rates is to match (1) the rate of money collection from ratepayers with (2) a straight line estimate of the life time cost of the plant utilized to provide the service.[57]

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[50] **Living Accounts**: Groups of property which may experience interim retirements, but for which retired property is expected to be replaced by comparable property, with or without improvements in technology.

[51] **Mass Property**: Continuous living group of property where routine replacements occur.

[52] **Whole Life**: Straight line depreciation over composite life without any correction for existing accumulated reserve imbalances.

[53] **Life Span**: Depreciation analysis method using a fixed life for a specific unit of property.

[54] **Remaining life**: Straight line depreciation over composite remaining life with corrections for existing accumulated reserves imbalances.

[55] **General plant accounts 391, 393, 394, 395, 397, and 398**: General Office, computers, communication equipment , small tools, and lab equipment.

[56] **Net Salvage**: Salvage value minus the cost of removal.

[57] 1. The book keeping associated with regulatory depreciation expense is to:

a) Allocate and record the money collected from ratepayers for depreciation purposes to specific plant accounts,

b) Account for the consumption of the invested capital as plant equipment is retired from service,

c) Account for the cost of removal, salvage value received, and any third party payments such as insurance proceeds,

d) Provide a continuous and consistent method of recording of the above listed costs as a historical record for use in future depreciation analysis.

Basic Formulas for Depreciation of Living Accounts:

Depreciation expense = (Depreciation Rate) * (Total Original Cost of Plant in Service)

$$\text{Rate \%} = \frac{100 - (\text{net salvage \%})}{\text{ASL}} = \frac{100}{\text{ASL}} - \frac{\text{Net Salvage \%}}{\text{ASL}}$$

Average Service Life (ASL) is the average number of years the property in the account is expected to remain in service. ASL is equal to the area under the survivor curve.[58] When working with living accounts, the survivor curve is not truncated, as it is expected that additional property will be placed into the account to replace property as it is retired.

NET SALVAGE = GROSS SALVAGE - COST OF REMOVAL

$$\text{Net Salvage \%} = \frac{\text{Net Salvage \$}}{\text{Retirement \$}} * 100 \qquad \text{Averaged}$$

When it is expected that the terminal net salvage rate will be equal to the interim net salvage rate, it is sufficient to use the single (Net Salvage % / ASL) term, as shown above.

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2. The cost of plant in service is recorded as the original installed cost. The installed cost of plant includes costs other than just labor and materials, it also includes costs such as project planning, engineering, sales taxes, transportation, insurance and cost of funds provided during construction, supervision, and all associated overhead costs. This original cost of plant in service stays with the equipment until it is retired from utility service. A transfer of ownership by the Company to another company or set of investors does not alter this cost, regardless of the amount of money paid by the new owners to attain ownership.

3. Only by order of the Commission may the cost of plant in service, the accumulated depreciation reserve, the depreciation rates, or the recording of depreciation expense be modified. Depreciation expense continues to be recorded and accumulated per Commission order until altered by a subsequent Commission order, even if the plant account in question is considered to be fully depreciated.

4. Depreciation expense is calculated as a percent of total plant in service for each plant account.

5. The cost of installed plant is recorded as plant in service on the date the equipment in question is used to provide the utility service.

6. The recorded cost of plant in service is independent of the source of funds used to pay for the installed plant. The source of funds may be from investors, loans, insurance proceeds, ratepayer or third party contributors, or simply still be accounts payable. The regulatory accounting system outside of the plant in service and depreciation section is used to address these issues.

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

### C. Depreciation Definitions

**Cost of Removal**: The cost associated with disposing of a retired unit of property, net of its salvage value.

**Life Span**: Depreciation analysis method using a fixed life for a specific unit of property.

**Living Accounts**: Groups of property which may experience interim retirements, but for which retired property is expected to be replaced by comparable property, with or without improvements in technology.

**Mass Property**: Continuous living group of property where routine replacements occur.

**Net Salvage**: Salvage value minus the cost of removal.

**Remaining life**: Straight line depreciation over composite remaining life with corrections for existing accumulated reserves imbalances.

**Whole Life**: Straight line depreciation over composite life without any correction for existing accumulated reserve imbalances.

### D. Staff's Analysis

Staff performed several depreciation analyses in developing its depreciation recommendation for KCPL.[59] The methods and components of each are discussed below, and a summary of the results of each is presented in Appendix 6, Schedule AR-3, as well as the Commission's currently-ordered rates for KCPL (Case No. EO-2005-0329).

**<u>Staff Case A</u>**

Staff recommends the Commission order KCPL to adopt the depreciation rates derived in its Case A study. Staff addresses three issues related to accumulated depreciation reserves and depreciation expense with this recommendation:

1. KCPL accumulated depreciation reserve has accrued $438,000,000 more than the appropriate reserve balance, as shown in Appendix 6, Schedule AR-2. This excess reserve is approximately 52% over accrued.60

2. KCPL will have collected approximately $169,000,000 from its ratepayers through December 31, 2010 for use against plant depreciation reserves.[61]

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[59] For all Staff cases the treatment of separate accounts assigned to the Hawthorn unit 5 rebuild use a life span remaining life method to adjust for the large depreciation reserve associated with the reimbursements received from insurance payments, as is currently ordered.
[60] This is in addition to the reserves held for Hawthorn unit 5 due to insurance reimbursements and in addition to reserves held for future cost of removal.

3. The addition of Iatan 2 to plant in service results in a large step increase in depreciation expense.

This proposal (1) suspends collection for estimated cost of removal until the excess reserves are reduced, and (2) provides for current cost of removal and salvage to be netted against the money collected from rate payers during the regulatory plan as additional amortization.[62] Staff's recommended depreciation expense of $85,177,000,[63] is approximately $14,000,000 annually less than KCPL's request, and does not include current cost of removal assigned to the additional amortizations.

For Case A, Staff used the following methods and assumptions:

1. Treatment of all non-nuclear Steam and Other production, Transmission, and Distribution accounts as living accounts, with mass property analysis and whole life depreciation rates,

2. Use of the life span method with remaining life rates for nuclear and Hawthorn 5 rebuild steam production accounts,

3. General plant accounts 391, 393, 394, 395, 397, and 398[64] have been left at the current ordered rates, pending identification by KCPL of retirements associated with recent office consolidations and relocations and clarification on the accuracy of historical retirement data.

4. Net Salvage[65] has been set to Zero for all plant accounts considering the amounts paid by customers for the additional amortizations,

5. Depreciation rates were estimated from analysis of Company retirement history, and review of data request responses regarding final retirements and descriptions of assets in specific accounts

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[61] In addition to the $132,221,058 based on December 31, 2010 of additional amortizations accrued pursuant to the Experimental Regulatory Plan, KCPL has accrued additional amortizations in the amount of $36,674,731 pursuant to Case No. EO-94-199.

[62] Staff recommends consolidating the additional amortizations accrued pursuant to Case No. EO-94-199, with the additional amortizations accrued pursuant to the Experimental Regulatory Plan. The recommended accounting treatment is discussed in the Direct Testimony of Staff Witness Cary Featherstone.

[63] This $85,177,000 is an estimate based on depreciable plant studied for end of 2008 plant balances and updated for Iatan additions in 2010.

[64] **General plant accounts 391, 393, 394, 395, 397, and 398**: General Office computers, communication equipment ,small tools, and lab equipment

[65] **Net Salvage**: Salvage value minus the cost of removal.

**Staff Case B**

While Staff recommends the Commission authorize KCPL's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case B" depreciation rates which are derived consistent with the methods used for AmerenUE's requested depreciation rates adopted by the Commission in File No. ER-2010-0036. In Case B, Staff used a life span analysis with remaining life rates for all Steam production accounts, including Nuclear. Consistent with the approach adopted by the Commission in File No. ER-2010-0036, all other accounts, including Combustion turbines, were treated as living accounts, with mass property analysis and remaining life rates. Use of life span enabled Staff to distinguish interim and final (terminal) retirements, and to separate net salvage into interim and final net salvage. Staff set the rate of terminal net salvage to 0 % consistent with the approach adopted by the Commission in File No. ER-2010-0036.

For purposes of calculating the depreciation rates associated with KCPL's Steam production accounts, Staff performed modest adjustments to the retirement dates KCPL presented in its request.[66] The removal of terminal net salvage from the life span analysis for the Steam Production accounts and the adjusted retirement dates results in annual depreciation expense of approximately $8,000,000 less than the KCPL's request, including the Staff use of the mass property method for combustion turbines. The overall depreciation expense derived from Case B is $91,750,000, as provided in Appendix 6, Schedule AR-3. Staff does not recommend Case B, but does recommend that if the Commission adopts KCPL's requested life span method of analysis for certain accounts that the Commission order the following:

[66] Retirements dates proposed by KCPL are found in KCPL Spanos Direct testimony Schedule JJS2010-1 at page II-27, and for Iatan 2 in the table shown as Schedule JJS2010-2. For depreciation purposes, Staff increased the life span for Iatan 2 from 50 to 60 years, and increased all life span assigned retirement dates by three months to revise retirement dates from June (peak load month) to Sept for each planned retirement year.

1. The proposed retirement date for Iatan 2 be extended by 10 years, from the Company requested 50 years to a life span of 60 years,

2. All proposed retirement dates for production equipment be extended at least 3 months from June to September of the retirement year.

For Case B, Staff used the following methods and assumptions:

1 The life span method was used for steam and nuclear production plant accounts, with retirements and net salvage broken into interim and final components, with terminal net salvage at 0%,

2 Remaining life depreciation rates used for all accounts to compensate for past over or under accruals,

3 Mass property analysis, with remaining life rates, was used for all other accounts, including Combustion turbines,

4 Depreciation rates were estimated from analysis of Company retirement history, and review of data request responses regarding final retirements and descriptions of assets in specific accounts.

**Staff Case C**

While Staff recommends the Commission authorize KCPL's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case C" depreciation rates which generally uses the same methods for the same accounts that were used to establish the current depreciation rates. Those treatments include:

1. All non-nuclear Steam and Other production, Transmission, and Distribution accounts as living accounts, with mass property analysis and whole life depreciation rates,

2. Use of the life span method with remaining life rates for nuclear and Hawthorn 5 steam production accounts,

3. One variation in Case C from current established rates is that for the nuclear plant accounts in Case C, net salvage was differentiated into interim and final net salvage components, with final net salvage set to zero.[67]

[67] The nuclear plant has a separate decommissioning fund.

**Staff Case D**

While Staff recommends the Commission authorize KCPL's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case D" depreciation rates which is identical to Case C, <u>except</u> depreciation rates were computed using a remaining life basis which reduced overall accruals due to the significant over accrual of accumulated depreciation reserves (52 % excess).

## E. Treatment of Steam Production Plant Accounts:

Modeling for depreciation analysis studies the mortality characteristics of plant in service. The mortality characteristics for various plant accounts may differ. Selection for treatment as Living accounts versus Dying accounts addresses one of the main differences in observed mortality characteristics. The Mass Property depreciation model is applied to plant accounts where each addition to the account as years go by (each vintage) is expected to have the same average service life - living accounts. The Life Span depreciation model is applied to plant accounts where each addition to the account as years go by (each vintage) is not expected to have the same average service life - dying accounts.

For electric plant equipment such as transmission or distribution systems, and power generation fleets, the Mass Property model is appropriate since all vintages are assumed to have the same average service life. With these types of accounts, it is assumed that all retirements will be recorded and retired property is expected to be replaced by comparable property, with or without improvements in technology. Treatment as a living account assumes the account as a whole will continue to live indefinitely[68]. If a specific termination date where all property of all

[68] The FERC and Commission rules prescribe accounts in a Uniform System of Accounts. The USOA prescribes that assets are accounted for by function. The FERC and Commission definition of DEPRECIATION states "...from causes which are **<u>known</u>** to be in current operation..." not implied, thought, believed, conjectured, assumed, etc. The

vintages will be retired at the same time becomes known, the treatment of the account should shift to a dying account.

For dying accounts, such as a large **single** electric generating plant or unit, the Life Span model is appropriate since a specific termination date where all property of all vintages will be retired is known or can be accurately estimated. Recent additions and replacements (recent vintages) will have shorter average service lives than the original installed vintage property which survived over the whole life span. Simple modeling of interim retirements for a single large production unit will not give a representative average service life estimate. This introduces two types of survivor curves used to determine the ASL (average service life).

The curves generated for these two methods are from two different historical data sets and are not interchangeable.

Staff's recommended Case A treats KCPL's production plant as a generation fleet. The retirement history provided by the Company includes sufficient final retirements from units previously removed from service to represent a fleet of production units. These final retirements represent the retirement of short lived property which occurs when a production unit is shutdown. It is up to the discretion of the analyst to determine which is the better representation of the future, the future projected retirement dates for individual units (dying account - life span), or the final retirement history of previous production units (living account - mass property). Staff's recommended Case A treats KCPL's production plant as a generation fleet using the living account Mass Property method.

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Commission has usually prescribed depreciation rates only by the main USOA functional accounts. It is Staffs opinion that the great majority of electricity produced in Missouri in the foreseeable future will continue to be generated by the spinning of a shaft (rotor & armature), powered by flowing water, steam, or combustion gases. Replacement of these facilities with wind turbines, solar, fuel cells, or capturing solar winds is not within the current depreciable lives of these facilities. Consequently the USOA functional accounts remain relevant as living accounts. While it is known that generation units will retire, it is also known from the Company's history that these facilities typically evolve piecemeal by replacement with similar functional units.

### a. Mass Property Type Survivor Curves

The ASL for an account is represented by the area under a survivor curve. A survivor curve is constructed which shows the percent of the account dollars which survive past a given age. The survivor (Iowa) curve used in the determination of the ASL is dependent on the model chosen. The Iowa curve derived for use with the Mass Property method is derived from analysis of a historical data set which includes all non reimbursed retirements, including all final retirements from any production units which have been removed from service. See Figure 1. The entire area under the curve represents the average service life. The survivor curve in Figure 1 has an Iowa curve designator of 47-R2. For the Mass Property type curve this designator indicates the average service life for this model is 47 years. Figure 1 is representative of a typical steam production boilers account for a fleet of production units where the retirement history studied includes all retirements from individual units which have been removed from service. Staff Case A used this method.

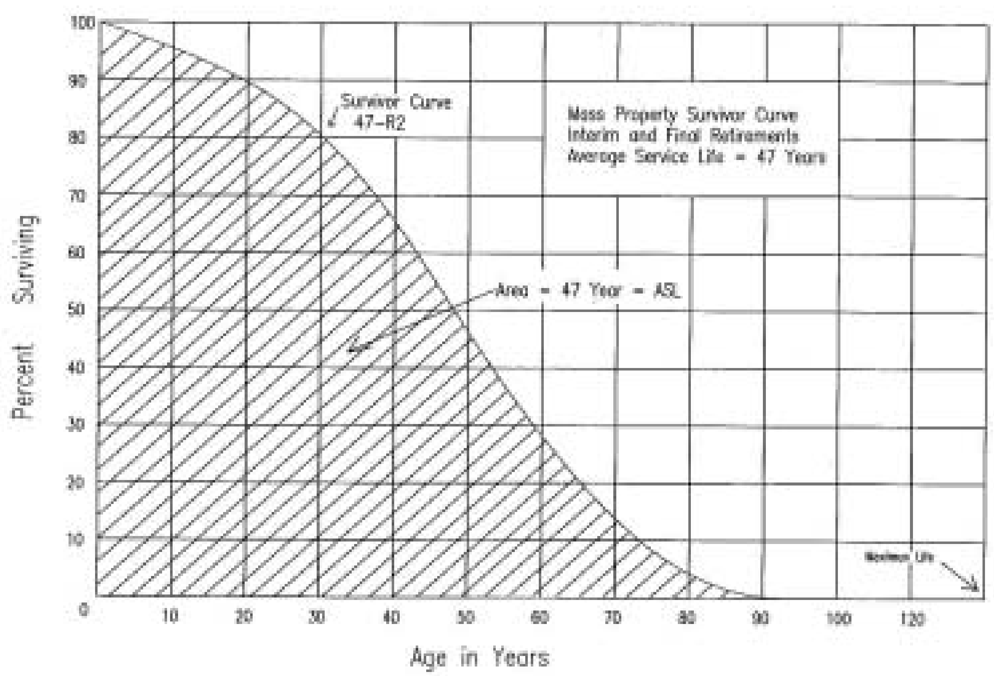


Figure 1 Mass Property Type Survivor Curve

KCPL has provided sufficient final retirement history including terminal retirements to allow reasonable estimation of average service lives for the Company's steam production accounts. The final retirement descriptions provided were used to identify the final retirement entries in the Company-provided historical data file.

Staff does not generally have a means of accurately predicting a retirement date and conducting life span analysis on each production unit, unless there is a specific issue with that unit, such as for Hawthorn 5.[69] The Commission has previously approved depreciation rates recommended by Staff that assigns depreciation rates to a fleet of similar production units.[70] Staff continues to support this assignment of depreciation rates to KCPL's fleet of generating units.

**b. Life Span Type Survivor Curve**

The Iowa curve derived for use with the Life Span method is from analysis of a historical data set consisting of only the interim retirements. See Figure 2. Note the survivor curve in Figure 2 has an Iowa curve designator of 57-R1. For the Life Span method this 57-R1 curve designation does **not** indicate the average service life. Final retirements are represented in Figure 2 with the vertical line drawn at the retirement or life span date. The area under the curve to the left of the life span date represents the average service life. In this figure the average service life is 47 years, the same as shown in Figure 1. The survivor curve by itself in Figure 2 is representative of interim retirements for a typical steam production boilers account. For a specific steam production unit the final retirements are represented by the truncation of the curve at the life span. The Company proposal used this method for each production unit. Both Figure 1 and Figure 2 show the same average service life of 47 years because, for this example,

[69] Hawthorn unit 5 is a special situation caused by the large reimbursed retirement received by the Company for that unit resulting from the re-building of that unit in June 2001 after a February 1999 explosion. Staff recommends tracking these funds separately.

[70] Typically all production units have main accounts (i.e. 311, 314, 322, 344) ordered at the same depreciation rate.

the life span for Figure 2 was specifically chosen at 60 years to produce a 47 year average service life.[71]

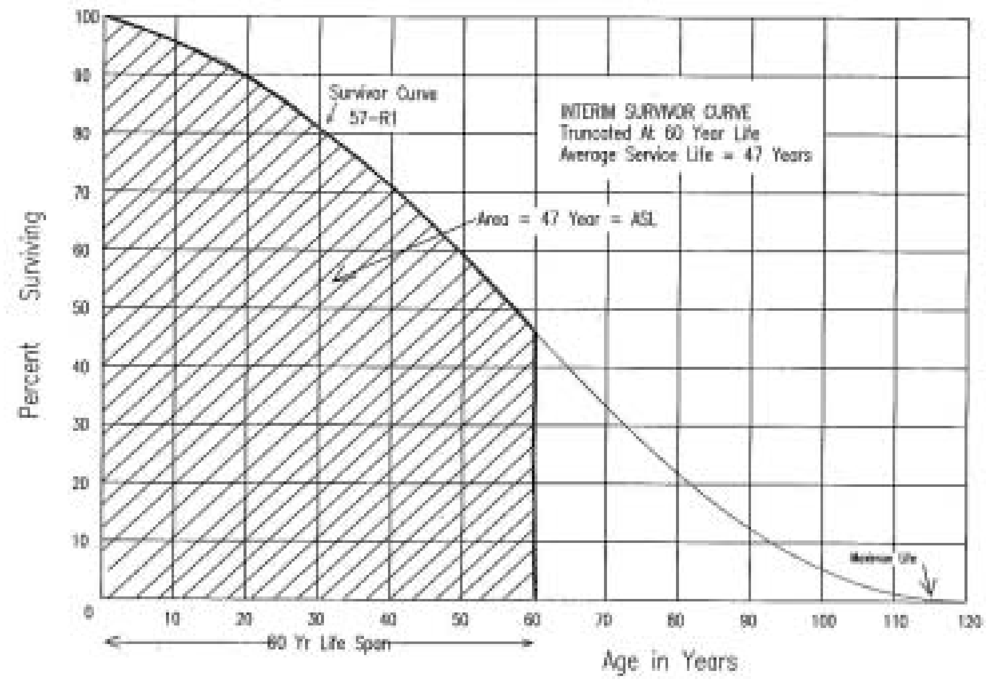


Figure 2 Life Span Type Survivor Curve

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[71] **Life Span Property Depreciation Rate Equation:**

The depreciation rate equation for Life Span property should be viewed as having four components, 1) interim retirements, 2) final retirements, 3) interim net salvage, and 4) final net salvage.

The Life Span Depreciation Rate Equation::

$$\text{Rate \%} = \frac{100}{\text{ASLs}} - \frac{\text{Interim Net Salvage \%}}{\text{ASLs}} - \frac{\text{Terminal Net Salvage \%}}{\text{ASLs}}$$

ASLs = average service life in years, from *interim* survivor curve truncated at life span.

Final retirements are represented by the vertical truncation line of the interim curve at the retirement date.

Net Salvage = gross salvage - cost of removal

$$\text{Interim Net Salvage \%} = \frac{\text{Net Salvage \$}}{\text{Interim Retirement \$}} * 100 * (1 - \text{fraction surviving at life span})$$

The term (1 – fraction surviving at life span) simply corrects this depreciation rate component to represent only the net salvage portion of current plant in service which is expected to retire as interim retirements.

$$\text{Terminal Net Salvage \%} = \frac{\text{Terminal Net Salvage \$}}{\underline{\text{Terminal}}\text{ Retirement \$}} * 100$$

For Terminal Net Salvage there is no correction for fraction surviving because at the terminal retirement date it is the current plant which is expected to survive plus the interim additions which are also retired.

## F. Treatment of Combustion Turbine Accounts

Staff recommends depreciation analysis treating the Other Production Plant accounts containing predominantly combustion turbine generators and associated facility equipment as a living fleet, using the mass property method. Prior rate case treatment for KCPL and all other recent electric company rates cases in Missouri have depreciation rates set for combustion turbine accounts using the Mass Property method.[72] Staff does not recommend adoption of KCPL's request to separately account for each combustion turbine and forecast retirement dates for each combustion turbine.

Mass Property treatment of all combustion turbine production units at all the Company facilities as one large continuous production system is an appropriate representation of the retirement and cost of removal which occurs. Even if one whole combustion turbine unit is replaced, much of the auxiliary and other site support equipment is expected to continue in use to provide service. Assuming the retirement activity is properly recorded, these retirements will be captured by using a living account mass property depreciation analysis.

## G. General Accounts Left at Prior Ordered Depreciation Rates

During Staff's review of the General accounts that KCPL has requested be switched to an Amortization or Square Curve method, Staff was unable to reconcile differences found between the Company provided historical data and prior case account balances in audit Staff work papers. The accounts involved are accounts 391, 391.01, 391.02, 393, 394, 395, 397, and 398.[73] This raised questions regarding recent office moves and retirements associated with the acquisition, and the possible effect on any depreciation analysis which used this historical data.

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[72] This is consistent with the Commission's Report and Order in AmerenMissouri's File No. ER-2010-0036.

[73] **General plant accounts 391, 393, 394, 395, 397, and 398:** General Office computers, communication equipment ,small tools, and lab equipment

At the time of this direct testimony, Staff recommends keeping the depreciation rates for these accounts at the prior case ordered depreciation rates, not switching to an Amortization Method, and not revising rates.

### H. Whole Life and Remaining Life

Whole Life depreciation rates may be viewed as the current rate of consumption of plant in service, with no correction in the assigned depreciation rate to adjust for any over or under accrued depreciation reserves. The current ordered depreciation rates, Staff Cases A, and Staff Case C use the Whole Life method of depreciation rate calculation. When Whole Life rates are used, an additional depreciation amortization may be assigned to correct reserve imbalances. For the Staff recommended Case A, an indirect amortization to correct for an over accrued reserve is proposed by setting the net salvage rate to zero for this rate case.

Remaining Life depreciation rates may be viewed as Whole Life rates which have been modified to account for over or under accrued depreciation reserves. This is accomplished by calculating the total depreciation accruals needed over the expected remaining life of the current plant in service, and dividing by the number of years remaining. Staff Case B and Staff Case D used remaining life rates to compute depreciation accruals.

Staff recommends the use of Whole Life depreciation rates for the following reasons:

> a) Whole Life rates show the current consumption of capital and provide a direct comparison for review with prior rate case or other company depreciation rates,
>
> b) Whole life rates provide a more consistent depreciation accrual in accounts where large changes in balances may occur due to unforeseen (at the time of a rate case) additions or retirements,
>
> c) Amortization assigned in conjunction with Whole Life rates allow setting a fixed time to apply the amortization, and

d) Fixed amortization associated with Whole Life rates do not fluctuate as plant balances change over time.

## I. Interim versus Final (terminal) Retirements and Net Salvage

For Staff's Case A, the survivor curve in the Mass Property method is projected to zero survivors. There is no distinction between interim and final retirements or net salvage. All retirements and net salvage for the current total installed plant in service is included in the depreciation rate assigned. The mass property type depreciation rate includes the collection of net salvage on 100% of the plant in service, not just what is expected to be retired as interim retirements.

Retired units which still physically exist have ongoing cost of removal and salvage which may continue for up to 20 plus year.[74] These net salvage costs should continue to be recorded and reflected in the depreciation rate analysis for all plant units as a fleet of production units. The representation of true historical cost for production units will not be reflected in the estimation of depreciation rates if only individual units currently in service are incorporated into the depreciation analysis, with the final retirement and terminal net salvage history ignored.[75]

In Staff's Case B, Staff treated the steam production plant as Life span property, and was able to distinguish between interim and final retirements. Interim retirements result in interim net salvage. Final (or terminal) retirements are associated with the removal or dismantling of the retired unit. For Staff's Case B, terminal net salvage was modeled at zero % to be consistent with the Life Span model the Commission approved in AmerenUE File No. ER-2010-0036.

For KCPL and its affiliated entities MPS and L&P, Staff has knowledge of five steam production facilities where approximately 15 boiler/turbine units have been shut down and removed from service. Four of these five steam production facilities, consisting of 11 of the

[74] The Ralph Green Steam units were retired in 1982 and disposed of in 2010, 28 years later.
[75] Typically all production units have main accounts (i.e. 311, 314, 322, 344) ordered at the same depreciation rate.

approximate 15 units, have been dismantled and disposed of from the plant sites. KCPL reports the total amount retired for these four steam production facilities as $33,141,318, with the associated cost of removal and salvage at $4,196,600 and $216,812, respectively. The resultant overall composite terminal net salvage rate from this historical steam production plant data is a negative 12%.

Four other steam production units, Hawthorn 1, 2, 3, and 4, were removed from service in 1984 and have not been dissembled and disposed of from the Hawthorn plant site. To date, 26 years later, the net salvage for these four units is a positive $1,189,010. The total retirement for these four units is $68,608,341, which results in a positive 1.7% net salvage at this time. At the end of 2008, there was $46,073,988 of net salvage contained in book reserves. This appears sufficient to cover the removal cost estimate of $7,066,650.[76]

*Staff Expert/Witness: Arthur W. Rice*

# IX. Current and Deferred Income Tax

## A. Current Income Tax

Current income tax for this case has been calculated by Staff consistent with the methodology used in KCPL's last rate case, Case No. ER-2009-0089. 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:

[76] 12% minus 1.7%, or 10.3% of the $68,608,431 retired.

**<u>Add Back to Operating Income Before Taxes:</u>**

- Book Depreciation Expense
- 50% Meals and Entertainment Disallowance
- Book Nuclear Fuel Amortization
- Book Amortization Expense

**<u>Subtractions from Operating Income:</u>**

- <u>Interest Expense – Weighted</u> Cost of Debt X Rate Base
- IRS Accelerated Tax Depreciation
- Deduction for Electric Utility Production Income
- IRS Nuclear Fuel Amortization
- IRS Other Amortization Deduction

**<u>Subtractions Federal Income Tax Credit:</u>**

- <u>Wind Production Tax Credit</u>
- <u>Research and Development Tax Credit</u>

The tax credit for research and development expenditures was reflected for setting rates by Staff in the calculation of current income tax in KCPL's rate case, Case No. ER-2007-0291. In that case, in response to U.S. Department of Energy (DOE) Data Request No. 55, KCPL indicated that it intended to file amended tax returns for years 2001-2005 for the purpose of reflecting allowable tax credits and current year tax deductions for research and experimental expenditures under Internal Revenue Code (IRC) Sections 41 and 174. It is Staff's position that the additional cash flow from a tax reduction from an amended tax return should be deferred and amortized for ratemaking purposes. This increase in cash flow to KCPL should be used to mitigate the Regulatory Plan Additional Amortization that KCPL's ratepayers are paying in current rates and will continue to pay until rates become effective in 2010 to recognize the "fully operational and used for service" date for KCPL's new coal burning generating facility, Iatan 2.

The occurrence of an extraordinary income event should be viewed in the same manner as an extraordinary cost event like KCPL's ice storm. Deferred accounting and amortization for ratemaking purposes should apply equally to both extraordinary costs and extraordinary income. KCPL's failure to take advantage of all available tax credits in prior years should not result in a cash windfall for its shareholders, but instead should be used to reduce the additional cash requirement collected from ratepayers in the Regulatory Plan Additional Amortization. The amount of additional cash flow provided by ratepayers through the Regulatory Plan Additional Amortization should be limited to funds unavailable from other sources.

Wind Credits used to reduce current income taxes relate to credits the Company is allowed from its ownership of the Spearville Wind Farm located in western Kansas and "fully operational and used for service" in September 2006. The Wind Credits were also taken as a reduction to current income taxes by Staff and reflected in rates as a result of KCPL's last rate case.

*Staff Expert/Witness: Paul R. Harrison*

### B. Kansas City Earnings Tax

Additionally, Staff normalized the Kansas City, Missouri earnings tax (KCET) in this rate case. This is included in the revenue requirement calculation as Adjustment E-214.1. This amount was treated as part of the tax calculation in KCPL's last rate case, Case No. ER-2009-0089 and included in the Staff's Schedule 11, Income Tax calculation. The adjustment to normalize the earnings tax is necessary to properly reflect an amount for the local Kansas City tax in current rates. During the review of KCPL costs, Staff discovered when this tax was made part of the tax calculation in KCPL's last rate case, it overstated costs. When the earnings tax was included in the tax calculation on Staff Accounting Schedule 11 and factored up for income taxes, it was creating a significant difference between the amount of earnings taxes actually paid and the level that was determined in the tax calculation. For example, in KCPL's last rate case, Staff included $887,104 for earnings taxes computed as part of the tax when ultimately the Company **actually** only paid $74,443 for 2009.

The actual earnings tax for KCPL, as determined by the city of Kansas City, is calculated by dividing the amount of gross receipts tax paid to Kansas City, and KCPL's payroll and plant identified within the Kansas City area by the amount of total company gross receipts, payroll and plant. This ratio is then multiplied by KCPL's total company net income to calculate the earnings taxes.

Because the Kansas City earnings are required as a right to conduct business in the city of Kansas City, Staff believes that 25% of the earnings taxes should be allocated to Kansas and GMO customers. The KCPL corporate office building and a predominate number of KCPL employees are located inside the Kansas City, Missouri area which result in a higher payment being made to the city of Kansas City for the earnings tax. As a result of the location of the office building and the number of employees that work out of it, two of the three amounts (payroll and plant) that are used to calculate the ratio that is used to determine the amount of the earnings taxes are increased significantly. Additionally, this ratio is multiplied by KCPL's total company net income (which includes Kansas and GMO net income. This causes the earnings taxes to be significantly higher than if the building and employees were located outside of the Kansas City Area.

In order to ensure a proper allocation of the earnings tax costs to various KCPL entities which benefit from the Company's corporate office function, the costs of the offices located in Kansas City and included in the earnings taxes should be assigned to each of these entities. Staff recommends that the Company perform a cost study with the goal of determining a reasonable and proper allocation of the earnings tax.

*Staff Expert/Witness: Paul R. Harrison*

### 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 difference related to accelerated tax depreciation.

*Staff Expert/Witness: Paul R. Harrison*

### D. Accumulated Deferred Income Tax

KCPL's deferred income tax reserve represents, in effect, a prepayment of income taxes by KCPL's customers. As an example, 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. Besides accelerated depreciation, Staff has also included deferred taxes specifically associated with the rate base inclusion of the pension liability.

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. Adjustment E-222.1 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. Adjustment E-223.1 reflects an annual amortization of the excess deferred taxes resulting from the reduction in the federal tax rate.

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. Adjustment E-224.1 reflects an annual amortization of the deferred investment tax credit.

*Staff Expert/Witness: Paul R. Harrison*

### E. Iatan No. 2 Advanced Coal Credit

In April 2008, KCPL was notified that its application filed in 2007 for $125.0 million in advanced coal investment tax credits (ITC) was approved by the IRS. The credit is based on the amount of expenses incurred on the construction of Iatan 2. Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the recapture of tax credits in the future, KCPL must meet or exceed certain environmental performance standards for at least five years once the plant is placed in service.

In February 2009, KCPL was served a notice to arbitrate by Empire District Electric Company (Empire), Kansas Electric Cooperative, Inc. (KEPCO) and Missouri Joint Municipal Electric Utility Commission (MJMEUC), joint owners of Iatan 2. The joint owners asserted that they are entitled to receive proportionate shares (or the monetary equivalent) of approximately $125 million of qualifying advance coal project credit for Iatan 2. As independent entities, the joint owners are taxed separately and the joint owners do not dispute that they did not, in fact, apply for the credits themselves. Notwithstanding this, the joint owners contend that they should receive proportional shares of the credit. This matter was heard by an arbitration panel in November 2009.

On December 30, 2009, the arbitration panel issued its order denying the KEPCO and MJMEUC claims but ordering KCPL and Empire to jointly seek a reallocation of the tax credit from the IRS giving Empire its representative percentage of the total tax credit, worth approximately $17.7 million for its twelve percent ownership. The order further specifies that if the IRS denies the parties' reallocation request or if Empire is allocated less than its proportionate share of the tax credits, KCPL will be responsible for paying Empire the full value of its representative percentage of the tax credits (less the amount of tax credits, if any, Empire ultimately receives) in cash. KCPL has recorded a $17.7 million liability in other current liabilities for this matter

GMO owns eighteen percent of the Iatan 2 power plant. Staff asserts that since GMO owns eighteen percent of Iatan 2, it is entitled to receive a proportionate share (or monetary equivalent) of the approximately $125 million of qualifying advance coal project credit for Iatan 2. Even though GMO is not taxed separately for book purposes, it is taxed separately for rate making purposes. For rate making purposes, GMO's cost of service is based upon its own rate base, revenues, expenses and income tax liability. Therefore, the Staff has made an adjustment to allocate eighteen percent of the advanced coal credit that KCPL received from the IRS to GMO. This allocation allows the GMO ratepayers to receive their portion of the advanced coal credit. This equates to approximately $26.5 million.

Because Iatan 2 is allocated between MPS and L&P, it is necessary to assign an appropriate amount for the advance coal credit to both of these entities. Staff has allocated the GMO share of the advance coal credit based on the allocation of Iatan 2 costs between MPS and L&P.

*Staff Expert/Witness: Paul R. Harrison*

## X. Jurisdictional Allocations

The Missouri Public Service Commission sets cost-of-service based rates only for the Missouri retail customers; however, not all the costs a utility incurs are to provide service to its Missouri retail customers. KCPL has both retail and wholesale customers in both Missouri and Kansas. Wholesale sales, as well as the retail sales in each state, are considered to be in separate "jurisdictions." Some costs to serve a particular jurisdiction may be directly assigned; however, other costs are not directly assignable to a particular jurisdiction and must therefore be allocated among the various jurisdictions. Costs that correlate with energy-generally costs that vary with energy consumption-are denoted as "energy-related" costs. Costs that correlate with demand-generally costs that do not vary with energy consumption, i.e. "fixed costs"-are denoted as "demand-related" costs. 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 allocated on the basis of demand. Variable costs, such as fuel, are more appropriate to allocate on the basis of energy consumption. In this case, jurisdictional allocation factors for demand and energy are calculated to assist in allocating demand-related (fixed) costs and energy-related (variable) costs between three applicable jurisdictions: Missouri and Kansas retail and wholesale operations. The application of a particular jurisdictional allocation factor is dependent upon the type of cost being allocated.

*Staff Expert/Witness: Alan J. Bax*

## A. Methodology

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

Demand refers to the rate at which electric energy is delivered to a system to match the energy requirements of its customers, generally expressed in kilowatts (kWs) or megawatts (MWs), either at an instant in time or averaged over a designated interval of time. System peak demand is the largest electric requirement occurring within a specified period of time (e.g., hour, day, month, season, and year) on a utility's system. In addition, for planning purposes, an amount of kWs or MWs in excess of anticipated system peak demand must be included for meeting required contingency reserves. 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 the three individual jurisdictions coincident to these system peak demands 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 used in the corresponding analyses.

Staff utilized a 4CP method - based on the monthly seasonal coincident peaks of the four summer months in the test period - to determine the demand allocation factors, the same method that the Commission ordered in Case No. ER-2006-0314, and which both KCPL and PSC Staff used in each subsequent KCPL rate case (Case Nos. ER-2007-0291 and ER-2009-0089). The 4CP method is appropriate for a utility such as KCPL that experiences dominant demands in the four summer months (June through September) in relation to the demands in the other eight months of a year. A utility that experiences a needle peek in a particular month may utilize the 1 CP method, or a utility that experiences comparatively similar hourly peaks in both winter and summer months may employ the 12 CP method. In analyzing the monthly demands in calendar year 2009, the test year of the current rate case, these demands are consistent with the monthly demands in the test periods associated with these three aforementioned rate cases.

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

1. Identify KCPL's peak hourly load in each month for the four - month period June 2009 through September 2009 and sum the hourly peak loads.

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

3. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

| | |
|---|---|
| • Missouri Retail Jurisdiction: | 0.5350 |
| • Kansas Retail Jurisdiction: | 0.4588 |
| • Wholesale Jurisdiction: | 0.0062 |
| • Total: | 1.0000 |

*Staff Expert/Witness: Alan J. Bax*

## 2. Energy Allocation Factor

Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor for each jurisdiction is the ratio of the total kilowatt-hours (kWh) used by the particular jurisdiction in the test year, calendar year 2009, to KCPL's total system kWh usage during the test year. Staff applied adjustments to these kilowatt hours to account for losses, for annualizations and for customer growth. Staff has calculated the following energy allocation factors for each jurisdiction:

| | |
|---|---|
| • Missouri Retail Operations: | 0.5694 |
| • Kansas Retail Operations: | 0.4235 |
| • Wholesale Operations: | 0.0075 |
| • Total: | 1.0000 |

These jurisdictional demand and energy allocation factors were provided to Staff witness Cary G. Featherstone, who used them 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 FERC. Therefore, it is necessary to specifically identify, then allocate and/or assign, KCPL's investment and expenses between these three jurisdictions. In order to develop a fully comprehensive cost of service analysis to identify the revenue requirements for KCPL, all of KCPL's costs for plant investment and the costs appearing on its income statement, must be appropriately placed in each of the jurisdictions it serves (Missouri Retail, Kansas Retail and Wholesale).

In developing KCPL's cost of service for the Missouri retail jurisdiction, Staff began with KCPL's records that it keeps in accordance with FERC accounting requirements. 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 the Missouri retail jurisdiction cost of service. However, when costs or investments were not directly assigned to the Missouri retail jurisdiction, Staff used the demand or energy allocation factor in apportioning an applicable share of an appropriate cost or investment to the Missouri retail jurisdiction.

KCPL's generation and transmission facilities, used to produce and transport electricity to KCPL retail customers in Missouri and Kansas as well as the FERC wholesale customers, are predominantly considered fixed assets. The costs and investments of these assets, as well as the related depreciation reserve accounts, are apportioned to the three jurisdictions on the basis of demand. As stated above, Staff applied the demand factor it developed for the Missouri retail jurisdiction, based on the 4 CP methodology, to allocate the appropriate portion of these aforementioned assets in its determination of KCPL's cost of service to the Missouri retail jurisdiction. Staff has consistently used the 4CP method since KCPL's 1985 Wolf Creek rate case. In each of the three rate cases filed by KCPL as part of the Regulatory Plan, Staff has used the 4 CP method.

KCPL allocates its identified distribution plant assets to the respective jurisdiction in which the respective assets are located. Plant identified in this way is referred to as site specific or *situs* plant. Staff used the actual amounts of distribution plant investment at June 30, 2010 to develop allocation factors for distribution plant and reserve to quantify only the distribution plant specific to Missouri operations.

The amounts in the FERC expense accounts found in KCPL's income statement (Schedule 9 of the EMS model) include costs broadly categorized as "production," "transmission," "distribution," and "general." Staff used the same allocation factors to identify costs to the Missouri retail jurisdiction that it used to allocate KCPL's investment in fixed production plant and transmission network assets. Therefore, Staff allocated production and transmission costs in KCPL's income statement to the Missouri retail jurisdiction by using the same demand allocation factor used to allocate the production plant and transmission network accounts to the Missouri retail jurisdiction. The approach of using the same allocators for allocating investments and costs to a jurisdiction is referred to as "expenses follow plant." Production plant expenses are associated with maintaining and operating the production plant; therefore, it is appropriate to use the same allocator for allocating both plant investment and plant expense. Similarly, transmission expenses are associated with maintaining and operating the transmission network, therefore, it is also appropriate to use the same demand factor to allocate transmission expenses found in KCPL's income statement.

Staff allocated KCPL's investment in common facilities, or general plant, based on a composite of the demand allocation factors Staff used to quantify the Missouri jurisdictional share of KCPL's production and transmission costs and the state site specific distribution costs. Once the plant and depreciation reserve amounts are allocated to Missouri based on the demand allocators for production and transmission plant and site specific allocation factors for distribution plant costs, these state specific costs form the basis for the general plant allocated to Missouri. Thus, the state jurisdictions allocation factors for general plant are based on the composite for the production, transmission and distribution plant costs. This composite general plant allocation factor is used to allocate general costs in the income statement.

For administrative and general costs, commonly referred to as the A&G costs, a variety of allocation factors were used to allocate these costs to the various expense accounts found in the income statement. Staff relied on the Company to identify and determine these allocation factors. The various allocation factors used were based on customers found in each jurisdiction in some cases. Other times, the factors used were based on numbers of KCPL employees in each jurisdiction. Each specific account had its own allocation factor that was used to allocate costs to Missouri, Kansas and/or FERC operations.

The energy allocation factor was used to allocate costs that are considered variable in nature. Variable costs fluctuate directly with increased or decreased electricity output. For example, the costs related to the variable component of fuel and purchased power expenses vary with increased or decreased loads. As more or less megawatts are generated or purchased, increased or decreased fuel and purchased power costs are directly affected. The fixed capacity, or demand charge, of capacity purchased power and capacity sales are allocated using the demand allocator, the same one used to allocate the fixed production and transmission costs. Fixed costs do not vary with electricity output.

The demand component of a capacity purchase or sale is to recover fixed charge costs of the facilities used to generate these transactions. As an example, the capacity sale requires the commitment on the part of KCPL to have dedicated generating capacity in place to meet the load requirements of the capacity sale customer. KCPL must have adequate generation in place to meet the load requirements of the capacity sale customer in much the same way it has to have fixed capacity to meet the system load requirements of its residential, commercial and industrial customers-referred to as its native load customers. Since the generating capacity is dedicated to meet the firm capacity sale requirements, the Company charges as part of the capacity contract a fixed charge amount to compensate it for reserving those assets to meet the capacity sale. The fixed charge can be thought of as a rate of return on, and of, the asset dedicated to making the capacity sale. When KCPL has a capacity purchase for energy, it also will have to pay a fixed charge amount to the seller of power to the Company. The fixed charge of the capacity sale or purchase is assigned or allocated to the jurisdictions on a demand allocation basis. At the same time, the energy component-the actual sale or purchase of energy is considered variable based and is appropriately allocated using the energy allocation factor.

The same infrastructure used to meet the system load requirements of KCPL's customers is also used to generate and transport electricity to firm and non-firm customers in the bulk power markets (off-system sales). The energy allocation factor was also used to allocate the revenues from these off-system sales between the jurisdictions. Since the non-firm, off-system sales market is made up of sales on a short term basis, no dedicated capacity is reserved for these sales. Traditionally, off-system sales have been allocated using the energy allocation factor since these costs of making these sales are generally variable in nature, primarily fuel costs. The more megawatts sold, the more fuel consumed and the more costs incurred to generate the electricity, or the more purchased power needed to make the sales, resulting in higher costs. These costs are directly variable to the sale or purchase, and thus the reason the energy allocation factor is properly used. The energy allocation factor has been used to allocate off-system sales in each of the last three KCPL rate cases by Staff. It has been used to allocate off-system sales revenues for The Empire District Electric Company and Aquila's MPS electric operations for many rate cases dating back to at least the 1990s.

*Staff Expert/Witness: Cary G. Featherstone*

## XI. Transition Cost Recovery Mechanism

On April 4, 2007, GPE, KCPL and Aquila filed an application with the Commission seeking authority for a series of transactions whereby Aquila would become a direct, wholly-owned subsidiary of GPE. On July 1, 2008, in Case No. EM-2007-0374, the Commission approved the series of transactions authorizing GPE to acquire Aquila. On July 14, 2008 GPE closed the acquisition.

In its Report and Order in Case No. EM-2007-0374, at page 282, in ordered paragraph 6(C), the Commission included the following condition to its authorizations:

> c. Great Plains Energy, Incorporated, Kansas City Power & Light Company and Aquila, Inc., shall, upon closure of the authorized transactions, implement a synergy savings tracking mechanism as described by the Applicants, and in the body of this order, utilizing a base year of 2006;

The Commission found that there was potential for significant savings as a result of the acquisition, and was supportive of the Applicants recovering the costs they incurred in combining the operations of KCPL and Aquila. These costs are referred to as transition costs. In the section of its Report and Order where it presented its "Final Conclusions Regarding Transaction and Transition Cost Recovery," on page 241, the Commission stated:

> Substantial and competent evidence in the record as a whole supports the conclusions that: (1) the Applicants' calculation of transaction and transition costs are accurate and reasonable; (2) in this instance, establishing a mechanism to allow recovery of the transaction costs of the merger would have the same effect of artificially inflating rate base in the same way as allowing recovery of an acquisition premium; and (3) the uncontested recovery of transition costs is appropriate and justified. The Commission further concludes that it is not a detriment to the public interest to deny recovery of the transaction costs associated with the merger and not a detriment to the public interest to allow recovery of transition costs of the merger.
>
> If the Commission determines that it will approve the merger when it performs its balancing test …, the Commission will authorize KCPL and Aquila to defer transition costs to be amortized over five years. (Footnote omitted.)

In the footnote 930 omitted above, the Commission stated:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCPL and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases.

The table below shows the total acquisition transition costs as of June 30, 2010:

| Jurisdiction | Total | % |
|---|---|---|
| **KCPL-MO** | **19,291,888** | **33.29%** |
| KCPL- KS | 15,591,495 | 26.90% |
| KCPL-Wholesale | 137,352 | 0.24% |
| **MPS-Retail** | **17,679,595** | **30.51%** |
| MPS-Wholesale | 69,545 | 0.12% |
| **SJLP Electric** | **4,440,472** | **7.66%** |
| SJLP Steam | 243,409 | 0.42% |
| Corporate Retained - Merchant | 500,727 | 0.86% |
| **Total Transition Costs** | | |
| **At June 30, 2010** | $57,954,483 | 100.00% |

KCPL and the Kansas Commission Staff agreed to an amount of transition costs recovered from the Kansas customers in the merger application filed with the Kansas Commission. This amount of recovery in Kansas is $10 million over five years [Kansas Commission Docket No. 07-KCPE-1064-ACQ]

While the Commission supported KCPL's and GMO's opportunity to present evidence for recovery of the transition costs in future rate cases in the statement above, the Commission did not specify the method with which this recovery is to be accomplished. The Commission made clear that KCPL and GMO would have to demonstrate the "reasonableness and prudence" of any transition costs [page 41, Footnote 930 of Commission Order in Case No. EM-2007-0374]

To demonstrate to the Commission the merits of the recovery of transition costs, the Company's synergy savings tracking model, as ordered by the Commission, compares the adjusted base year of non-fuel operations and maintenance (non-fuel O&M) of standalone KCPL and Aquila operations in 2006 to the combined KCPL and GMO operations of 2009. The KCPL synergy model shows that the annual synergies realized comparing 2006 to 2009 periods of time amount to $48.5 million. The cumulative transition costs at June 30, 2010, less the amount retained by GPE corporate and the amount assigned to Kansas based on its agreed to maximum amount of $10 million results in over $51.8 million.

The comparison of the 5-year proposed amortization of the transition costs of $10,372,452 (total transition costs less the amount over Kansas limit and corporate retained) to the annual non-fuel O&M synergies described in KCPL's tracking model of $48.5 million shows that in its analysis KCPL believes that synergy savings exceed the level of amortized transition costs.

While the Company's demonstration that annual synergy savings exceed amortized transition costs would suggest that ratepayers have sufficiently realized those savings, the contrary is true. KCPL has benefited significantly from regulatory lag in flowing savings from the acquisition to GPE shareholders. Staff believes GPE has greatly benefited from the retention of the any savings that have existed from the Aquila acquisition - both from the time prior to the closing of the acquisition and since the July 14, 2008 closing of the acquisition.

Regulatory lag is the difference between when lower or higher costs are measured in one time period and when the lower or higher costs are reflected in rates in a subsequent time period. In the case of the acquisition savings, KCPL and GMO have received the benefits of any costs savings arising from the acquisition well in advance of those savings being passed on to the customers of those entities. To the extent savings are retained by KCPL and GMO, GPE will directly benefit with higher earnings rewarding shareholders for the retained savings.

Staff believes the Commission, in its order regarding the acquisition of Aquila, set out a standard that must be met to allow a recovery of the transition costs. This standard was to require KCPL to not only make a showing that savings existed in excess of the transition costs before any recovery in rates would be permitted but a demonstration that the Company has not already benefited from those savings sufficiently to already recover the transition costs. As an example, it would not be reasonable to recover the transition costs if GPE, KCPL and GMO have already recovered those costs through savings retained for the Company. Therefore, Staff believes that KCPL must demonstrate that it has not sufficiently recovered the transition costs from retained savings before customers should be required to pay higher rates for the transition costs. To put it another way, to the extent any transition costs that have already been recovered through savings from the acquisition, thereby directly benefiting the GPE entities, the Company should not request recovery of that portion of the transition costs. And certainly, if all transition costs have been recovered through acquisition savings, then no transition costs should be reflected in rates. The fundamental question that must be answered in any kind of synergy analysis is: "when did the savings occur and, more importantly, when did customers receive the benefits from such savings?"

The key element to demonstrating that KCPL has either already recovered all transition costs or a portion of those costs from regulatory lag is in establishing when the savings occurred and when, if ever, those savings were reflected in rates. Thus, the development of a timeline of when synergy savings occurred and when they began to appear in rates is critical. Without such an analysis the request for rate recovery of any transition costs is premature. It is Staff's belief that neither KCPL nor GMO has attempted to analyze the impacts of when the acquisition savings occurred; the extent savings have been retained by the GPE entities; the extent the transition costs have been either fully or partially recovered from acquisition savings and the extent it is even necessary for customers to pay any amount for any of the acquisition costs. Until that analysis is performed by KCPL and GMO, then no transition costs should be placed in rates. Once that type of analysis is performed by the Company then would it even be appropriate to consider what if any of the transition costs should be in rates.

Clearly, to the extent KCPL and GMO have recovered any amounts of the transition costs there should be no recovery from customers. However, if such recovery is necessary then there must be a showing that either no amount of transition costs have been recovered or that only a portion of the amount of acquisition costs have been recovered. Once this has been done then it would be appropriate to determine the proper cost recovery.

As a start to this analysis, it is critical to identify the time when acquisition savings started and when those savings were either retained by KCPL and GMO and when they were passed on to customers. The following table identifies critical dates relating to rate case activity of KCPL and Aquila prior to the acquisition and after its completion. This table identifies when those rate cases occurred, what the established known and measurable dates were used in those cases and when rates went into effect.

| Company Name | Case No. | Test Year | Update Cutoff | True-Up Cutoff | Effective Date of Rates |
|---|---|---|---|---|---|
| Aquila | ER-2007-0004 | Calendar 2005 | June 30, 2006 | December 31, 2006 | June 3, 2007 |
| KCPL | ER-2007-0291 | Calendar 2006 | March 31, 2007 | September 30, 2007 | January 1, 2008 |
| KCPL | ER-2009-0089 | Calendar 2007 | September 30, 2008 | No True-Up | September 1, 2009 |
| KCPL GMO | ER-2009-0090 | Calendar 2007 | September 30, 2008 | No True-Up | September 1, 2009 |
| KCPL | ER-2010-0355 | Calendar 2009 | June 30, 2010 | December 31, 2010 | May 4, 2011 |
| KCP&L GMO | ER-2010-0356 | Calendar 2009 | June 30, 2010 | December 31, 2010 | June 4, 2011 |

The first two rate cases are the last Missouri KCPL and Aquila rate cases before the GPE-Aquila acquisition case, where KCPL and Aquila were still standalone entities. As can be seen, because no documented synergy savings occurred prior to July 14, 2008, no synergies were flowed to ratepayers in either of those rate cases. The true-up period for the 2006 Aquila case was December 31, 2006 while the true-up period for the 2007 KCPL case was September 30, 2007 with rates effective January 1, 2008. Certainly no amounts of savings from the acquisition were given to customers.

The next two rate cases are KCPL and GMO's first electric rate cases following the acquisition. The test years utilized were calendar year 2007, which would not have included any documented synergy savings. The next data point in this analysis is September 30, 2008, the test year update used in Staff's direct case. The purpose of a test year update is to update and utilize cost data closer to when Staff files its direct filing. In Staff's cost of service model, the test year data remains unchanged when utilizing updated numbers. The test year update includes only selected data, such as rate base, payroll, and insurance, among other known and measurable items commonly included in a test year update. It does not move all costs of service to the update cutoff period, and, therefore, Staff did not capture all of the merger synergies through September 30, 2008. The next key date listed is September 1, 2009, the effective date of rates in Case Nos. ER-2009-0089 and ER-2009-0090. This is the very first date that KCPL and Aquila ratepayers could realize any savings from the GPE acquisition of Aquila. The savings realized would have only been any adjustments made to the cost of service using September 30, 2008 updated numbers, such as payroll and insurance. Any savings occurring prior to September 1, 2009 were retained by both KCPL and GMO.

The last two entries are KCPL's and GMO's pending rate cases, including this one. In looking at regulatory lag for synergy savings, presently the final known date is the effective date of rates of the instant case, File No. ER-2010-0355, May 4, 2011, and GMO's pending case, File No. ER-2010-0356, June 4, 2011. This is the first date KCPL ratepayers will realize the synergy savings that occur after September 30, 2008, and most of the synergy savings that occur after July 14, 2008. The table below identifies how long GPE shareholders have retained the synergy savings due to regulatory lag based on the dates of test year updates and the effective dates of rates:

| Type of Savings | Beginning Date Of Savings | Date Flowed Through to Rates | Lag (In Months) |
|---|---|---|---|
| Updated In Test Year Update | July 14, 2008 | September 1, 2009 | 13.6 |
| Post Update Savings, KCPL | October 1, 2008 | May 4, 2011 | 31.1 |
| Post Update Savings, GMO | October 1, 2008 | June 4, 2011 | 32.1 |
| Savings Not in Test Year Update, KCPL | July 14, 2008 | May 4, 2011 | 33.7 |
| Savings Not in Test Year Update, GMO | July 14, 2008 | June 4, 2011 | 34.7 |
| Savings Not in Current Test Year Update | January 1, 2010 | Unknown | Unknown |
| Post Update Savings, KCPL and GMO | July 1, 2010 | Unknown | Unknown |
| Post True-up Savings, KCPL and GMO | January 1, 2011 | Unknown | Unknown |

Based on this table, it is apparent KCPL ratepayers could not have realized any synergy savings for at least 13 months after the acquisition and that it might take them as long as 33 months to realize savings from the acquisition. As demonstrated above, GPE shareholders have reaped the benefits of regulatory lag and have retained significant savings while customers have waited over at least one year for the benefit of those savings to flow to them through rates. The last three lines of the table are dates of costs from the current rate case. For savings not reflected in Staff's test year, test year update, and true-up, customers will wait an indefinite amount of time to receive the synergy savings while shareholders enjoy the benefits of them.

To understand KCPL's true savings from the acquisition, one must examine the synergies from the Company's perspective. In addition to creating and maintaining a tracking model to compare the adjusted 2006 base year to 2009 as ordered by the Commission, KCPL prepared and maintains specific synergy charters to track specific synergy savings, including those included in and beyond the savings identified in the tracking model. KCPL has a cumulative database of these synergy charters by the quarter in which they occurred, total by year, and by individual charter. The table below summarizes the cumulative synergy savings as they appear in the charter database in the response to Data Request No. 146, File No. ER-2010-0355:

| | **Category** | |
|---|---|---|
| **Period** | **Regulated-Savings** | **Corporate-Savings** |
| **Q3** | $7,049,467 | 17,927,511 |
| **Q4** | 13,565,146 | 31,022,978 |
| **2008 Total** | **20,614,613** | **48,950,489** |
| **Q1** | 11,267,258 | 19,189,044 |
| **Q2** | 14,296,977 | 19,062,379 |
| **Q3** | 19,711,085 | 19,427,888 |
| **Q4** | 19,286,671 | 20,322,463 |
| **2009 Total** | **64,561,991** | **78,001,774** |
| **Q1** | 15,875,340 | 20,518,886 |
| **Q2** | 19,753,175 | 20,570,612 |
| **2010 Total** | **35,628,515** | **41,089,498** |
| **Total** | | |
| **Cumulative** | $120,805,119 | $168,041,761 |

The column labeled "Corporate" are corporate retained synergies that KCPL has identified that are not included in the synergy savings tracking model the Commission ordered, and are not and will not be flowed to ratepayers. These savings include reduced interest expense from the upgrade of Aquila's debt post-acquisition, line of credit fees, and corporate redundant expenditures. Although KCPL has reaped $168,041,761 of benefits through June 30, 2010 from the acquisition, referencing the previous table of transition costs, it has retained a mere $500,727 of transition costs (see Corporate Retained – Merchant line).

In examining the Company's documented regulated synergy savings in relation to the table of relevant dates previously provided, KCPL retained all synergy savings realized from July 14, 2008 to September 1, 2009. Assuming the savings in Quarter 3 of 2009 occurred ratably over the quarter, KCPL retained over $52.7 million of synergy savings before any benefits flowed to ratepayers. KCPL has identified total regulated transition costs of $51.9 million. Comparing the transition costs to the savings identified in the table above KCPL has already recovered the entire amount plus an additional $886,948 [$52,749,210 through September 1, 2009 savings less $51,862,262 of transition costs].

Even more important in considering the level of actual savings KCPL and GMO have retained from the acquisition is the amount of savings identified for 2009 of $64.5 million and through the 6 months ending June 30, 2010 of $35.6 million, which total $100.1 million. Considering the $168 million of acquisition savings retained by GPE, GPE and its KCPL and GMO entities have received over $268 million of benefits from the Aquila acquisition. Those amounts more than offset the transition costs. Customers have seen a fraction of those savings. To provide KCPL and GMO recovery of transition costs would provide a double recovery of those costs.

In its Report and Order in Case No. EM-2007-0374 where the Commission authorized KCPL, Aquila and GPE to perform the transactions for GPE to acquire Aquila, the Commission, as quoted earlier, stated on page 241, "The Commission further concludes that it is not a detriment to the public interest to deny recovery of the transaction costs associated with the merger . . . ." If one assumes KCPL intended the corporate retained benefits to offset any of the transaction costs for which the Commission denied recovery, then KCPL has recovered far more costs than expended. In response to Data Request No. 461 in this case, KCPL stated that the total transaction costs related to the acquisition of Aquila is over $40.2 million. The corporate retained synergies that exceed the transaction costs net of the transition costs the companies have retained totals $127.3 million of cash flow to shareholders.

The remaining "bucket" of synergy savings is the savings that took place before GPE acquired Aquila. In its response to Data Request No. 460 in this case, File No. ER-2010-0355, KCPL stated, "[We] have not tracked or evaluated synergy savings for any period prior to the completion of the acquisition on July 14, 2008." If there were any synergy savings before GPE acquired Aquila, the companies would have retained the additional synergies in 2008, before flowing them through rates. It is typical for companies to lose employees, thus reduction of payroll costs, during course of a merger. Many employees, fearing loss of jobs, will leave the merging companies to seek employment elsewhere.

It is important to note that KCPL has not begun to amortize the deferred transition costs. In footnote 930 of its Report and Order in Case No. EM-2007-0374 quoted earlier, the Commission stated:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCPL and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs **included in the test year cost of service expenses** in future rate cases. (Emphasis added.)

In its finding of fact number 327 appearing on page 122 of its Report and Order the Commission found:

> 327. Applicants request that the Commission allow the surviving entities to defer both transaction and transition costs and to amortize them over a five-year period beginning with the first rate cases post-transaction for Aquila and KCPL subject to "true up" of actual transition and transaction costs in those future cases. (Footnote omitted.)

And, in its Conclusions of Law section of that same Report and Order, on page 239, the Commission stated:

> The Applicants have requested that the Commission authorize the recovery of the transaction and transition costs associated with the merger by amortizing them over a five-year period. This period would begin with the first rate cases post-transaction for Aquila and KCPL subject to "true up" of actual transition and transaction costs in future cases.

Based on these statements in its Report and Order in Case No. EM-2007-0374, Staff believes the Commission expected KCPL to begin amortizing the transition costs beginning with the first rate cases post GPE's acquisition of Aquila. The first rate cases after the acquisition were filed by KCPL and GMO on September 5, 2008 as Case Nos. ER-2009-0090 and ER-2009-0089, respectively. The effective date of new rates in both cases was September 1, 2009. The test year for the instant case is calendar year 2009, therefore, had KCPL begun amortizing transition costs on September 1, 2009, four months of the amortization would have already been expensed in the test year—September, October, November and December.

Staff believes both KCPL and GMO should have started any amortization of the transition costs starting with the effective date of the last rate cases, September 1, 2009. The Commission authorized a general rate increase which should have triggered the starting of the amortizations for the transition costs.

Based on the foregoing, KCPL and GMO have already recovered all of the transition costs of GPE's acquisition of Aquila through regulatory lag. Therefore, Staff has not included any amount of amortized transition costs in its cost of service for KCPL.

*Staff Expert/Witness: Keith A. Majors*

## Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation
-David Murray

Appendix 3 - Relevant Pages of Energy Efficiency Advisory Groups Status Report
- John A. Rogers

Appendix 4 - KCPL Customer Program Expenditures - Henry E. Warren

Appendix 5 - Support for Transmission Tracker Testimony - Daniel I. Beck

Appendix 6 - Staff Recommended Depreciation Rates - Arthur W. Rice

**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF MISSOURI**

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AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 80-81, 180-183; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J Bax
Alan J. Bax

Subscribed and sworn to before me this 10th day of November, 2010.

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

D Suzie Mankin
Notary Public

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AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Daniel I. Beck, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 149-154; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Daniel I. Beck
Daniel I. Beck

Subscribed and sworn to before me this 10th day of November, 2010.

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

D. Suzie Mankin
Notary Public

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AFFIDAVIT OF WALT CECIL

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Walt Cecil, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 58-59, 60-61, 78-80; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Walt Cecil

Walt Cecil

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-10, 183-187; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Cary G. Featherstone

Cary G. Featherstone

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF CAROL GAY FRED

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Carol Gay Fred, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 137-141; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Carol Gay Fred

Carol Gay Fred

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Randy S. Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 154-157; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy S. Gross

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 49-51, 66-70, 72-74, 76-77; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

V. William Harris

V. William Harris

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
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AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 51-52, 86-90, 172-180; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Paul R. Harrison

Paul R. Harrison

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
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AFFIDAVIT OF CHARLES R. HYNEMAN

| | | |
|---|---|---|
| STATE OF MISSOURI | ) | |
| | ) | ss. |
| COUNTY OF COLE | ) | |

Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 90-98, 134-137; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Ch R. Hy
Charles R. Hyneman

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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D Suzie Mankin
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AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Hojong Kang, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 130 - 134 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Hojong Kang

Subscribed and sworn to before me this 10 th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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D Suzie Mankin
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AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 59-60, 61, 63-64, 65-66; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Manisha Lakhanpal

Manisha Lakhanpal

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Shawn E. Lange, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 74-75, 78, 81; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Shawn E. Lange
Shawn E. Lange

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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AFFIDAVIT OF KAREN LYONS

| | | |
|---|---|---|
| STATE OF MISSOURI | ) | |
| | ) | ss. |
| COUNTY OF COLE | ) | |

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 39-46, 102-106, 107-112, 113-115, 120-121, 144-146; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Karen Lyons

Karen Lyons

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF KEITH A. MAJORS

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Keith A. Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 53, 121-126, 146-148, 187-199; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Keith A. Majors

Keith A. Majors

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 77-78; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

Erin L. Maloney

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Amanda C. McMellen, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 62-63, 70-71, 115-116, 119-120; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Amanda C McMellen
Amanda C. McMellen

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 10-39, 106-107; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 10th day of November, 2010.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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AFFIDAVIT OF BRET G. PRENGER

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Bret G. Prenger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 47-49, 51, 81-86, 98-102, 112-113, 116-118, 148; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Bret G. Prenger

Bret G. Prenger

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF ARTHUR W. RICE, PE

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Arthur W. Rice, PE, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 158-172; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Arthur W Rice PE

Arthur W. Rice, PE

Subscribed and sworn to before me this 10th day of November, 2010.

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

Notary Public

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AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 126-130 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A Rogers

John A. Rogers

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF HENRY E. WARREN, PHD

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Henry E. Warren, PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 142-144; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E Warren
Henry E. Warren, PhD

Subscribed and sworn to before me this 10th day of November, 2010.

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

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AFFIDAVIT OF SEOUNG JOUN WON

STATE OF MISSOURI )
) ss.
COUNTY OF COLE )

Seoung Joun Won, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 56-57, 61-62, 64-66; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won

Subscribed and sworn to before me this 10th day of November, 2010.

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

Notary Public