KCP&L-210

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 reflected 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:

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: **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

[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.

<u>2. Capital Market Conditions</u>

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. <u>Capital Structure</u>

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

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[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.

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[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%.

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[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 switcher[31] 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.

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 25th 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

<u>1. Fixed Costs</u>

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

<u>2. Fixed Adders</u>

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

5. Variable Costs

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.

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 <u>Weather Normalization of Electric Loads, Part A: Hourly Net System Loads</u> [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

[35] <u>Weather Normalization of Electric Loads, Part A: Hourly Net System Loads"</u> (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

<u>6. FAS 106 – Other Post Employment Benefit Costs (OPEBs)</u>

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