MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

Great Plains Energy, Incorporated
GREATER MISSOURI OPERATIONS
GMO- L&P STEAM

CASE NO. HR-2009-0092

Test Year 2007
Updated through September 30, 2008
With True-up as of March 31, 2009

Jefferson City, Missouri
February 13, 2009

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

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COST OF SERVICE REPORT

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COST-OF-SERVICE REPORT

I. Background of Great Plains Energy and KCP&L - Greater Missouri Operations Company

KCP&L Greater Missouri Operations Company ("GMO" or "the Company") is a corporation duly organized and existing under the laws of the State of Missouri. GMO is a regulated public utility operating in the state of Missouri. It also provides wholesale electricity to several municipal customers under the jurisdiction of the Federal Energy Regulatory Commission. GMO provides industrial steam service to several industrial customers located in and around the Company's Lake Road Generating Facilities. GMO distributes and sells electric service to the public in its certificated areas in 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. GMO is wholly owned by Great Plains Energy ("GPE") and an affiliate of Kansas Power & Light Company ("KCPL")

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.

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 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. Prior to the July 14, 2008 acquisition by GPE, GMO was formerly known as Aquila, Inc. and before that UtiliCorp United, Inc.

In this report, depending on the name it had at the pertinent time what is now named KCP&L Greater Missouri Operations Company may be referred to as GMO, Aquila or UtiliCorp. GPE acquired Aquila in 2008 after the Missouri Public Service Commission ("Commission"), in Case No. EM-2007-0374, in a *Report and Order* made effective July 11, 2008, approved the joint application of GPE, KCPL, and Aquila for authority to engage in a series of transactions where GPE would acquire Aquila after it divested all of its operations except its Missouri electric and steam operations, and merchant services operations. ted in Mississippi, (Crossroads), and certain residual natural gas contracts. After GPE acquired Aquila the Commission by an order effective August 8, 2008 entered in Case No. EN-2009-0015, "recognize[d] the name change of Aquila, Inc., dba Aquila Networks – L&P and Aquila, Inc. dba Aquila Networks – MPS to Aquila, Inc., dba KCP&L Greater Missouri Operations Company and by a *Report and Order* effective December 3, 2008, entered in Case No. EN-2009-0164, recognized the name change of Aquila, Inc., d/b/a KCP&L Greater Missouri Operations Company to KCP&L Greater Missouri Operations Company.

The part of GMO's service territory in and about St. Joseph, Missouri has different rates than the remainder of its service territory, which is about Kansas City, Missouri. For rate setting purposes a revenue requirement must be developed for each and also for each utility service provided there. For GMO that means two electric revenue requirements and one steam revenue requirement. Before GPE acquired Aquila, with Commission authorization used the name Aquila Networks – L&P for its regulated operations in and about St. Joseph and Aquila Networks – MPS for the remainder of its regulated Missouri operations. While GMO no longer uses the names Aquila Networks – L&P or Aquila Networks – MPS, because of the need to develop three different revenue requirements in this case based on operations associated with those names in the past, and GMO having provided no better way to refer to them, Staff will use "GMO L&P" or "L&P" when referring to GMO's regulated operations that were formerly referred to as Aquila Networks – L&P and "GMO MPS" or "MPS" when referring to GMO's regulated operations that were formerly referred to as Aquila Networks – MPS.

II. Executive Summary

Please summarize the Staff's filing.

Curt Wells, of the Commission's Utility Operations Division, and Cary Featherstone, of the Commission's Utility Services Division sponsor Staff's Cost of Service Report in this proceeding that is being filed concurrently with testimony of Mr. Wells and Mr. Featherstone. Staff's Cost of Service Report supports Staff recommendation regarding the amount of the rate increase that Staff expects will be needed in this case.

This is an overview of the results of Staff's review into the general rate increase request made by GMO on September 5, 2008. Several members of the Commission Staff conducted Staff's review by examining all relevant and material components making 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 recommends that GMO be permitted to increase its steam rates to recover an additional $1 million per year for L&P steam. This amount includes an amount for an allowance for known and measurable changes that is expected to occur as result of the true-up in this case.

Cost increases will likely include payroll, payroll related benefits such as pensions and medical costs.

The following represent a non-exhaustive list of areas that make up Staff's filing:

- Rate of Return proposed by Staff for both MPS and L&P electric
- Depreciation expense
- Fuel costs for L&P steam
- Pension costs for both MPS and L&P electric
- Acquisition savings and transition costs for L&P steam

III. KCP&L Greater Missouri Operations Company's Rate Case Filing

GMO filed rate cases on September 5, 2008, for both its electric and steam operations. These cases have been designated as Case Nos. ER-2009-0090 and HR-2009-0092.

For L&P steam service, GMO is requesting an increase in the amount of $1.3 million, representing a 7.7% increase. For MPS, GMO is requesting a rate increase in the amount of $66 million, representing a 14.4% increase. For L&P electric service, GMO is requesting an increase in the amount of $17.1 million, representing a 13.6% increase; GMO proposes a rate of return on equity of 10.75% applied to the 53.82% equity capital structure for GPE.

KCPL also filed its rate case on September 5, 2008 reflecting an increase in Missouri retail rates of $101.5 million. This request represents a proposed 17.5% increase. The Commission designated this rate case as Case No. ER-2009-0089. KCPL proposes a rate of return on equity of 10.75% applied to the 53.82% equity capital structure for GPE.

A. Test Year

The test year being used in this case, as well as the KCPL case, is the 12-month period January 1, 2007, through December 31, 2007, updated for known and measurable changes through September 30, 2008, and trued-up through March 31, 2009.

IV. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return (ROR) of 8.03 percent to 8.54 percent for KCPL Greater Missouri Operations (GMO). Staff's rate of return recommendation is based on a recommended return on common equity (ROE) of 9.25 percent to 10.25 percent, midpoint 9.75 percent, applied to GMO's September 30, 2008, common equity ratio of 51.03 percent. Staff's recommended ROE is driven by its comparable company analysis using a multiple-stage discounted cash flow (DCF) analysis. Staff continues to believe that the DCF methodology is the most reliable method available for estimating a utility company's cost of common equity. However, Staff decided to deviate from the constant-growth, single-stage DCF model (hereinafter referred to as the "constant-growth DCF") in this case because of current market conditions that appear to be causing analysts' earnings per share (EPS) growth rate estimates and stock prices to be inconsistent. A constant-growth DCF analysis using analysts' EPS growth rate estimates results in unreliable cost of equity estimates. If investors are fearful about the current recession and are concerned that the economy will continue to grow at a slow pace, then it is difficult to believe that investors would consider these analysts' estimated growth rates to be sustainable. For this reason, Staff deviated from its traditional reliance on the constant-growth DCF. In its CAPM analysis, Staff's use of historical earned risk premiums along with very low U.S. Treasury bond yields results in low estimated costs of common equity. Staff believes that its approach in this case attempts to make sense of the widely divergent results obtained from the constant-growth DCF using analysts' EPS growth rate estimates and the CAPM results using historical earned risk premiums and low treasury yields.

Staff's estimated cost of capital for GMO's steam operations is the same as its recommendation for GMO's electric utility operations. Staff is not aware of any steam utilities to use to estimate a cost of common equity for GMO's steam operations. In fact, in the recent Trigen-Kansas City Energy Corporation's rate case, Case No. HR-2008-0300, Staff used a natural gas utility proxy group to estimate the cost of common equity cost for Trigen's steam operations. Because Staff is not aware of any pure-play publicly-traded steam companies available for estimating a steam cost of common equity, using a comparable group of regulated utility companies seems to be a reasonable alternative. Staff believes it is reasonable to use its cost of common equity estimate for GMO's electric operations in Case No. ER-2009-0090 for GMO's steam operations in this case. This is the same approach Staff used in the last rate case involving GMO's steam operations, Case No. HR-2005-0450.

Staff's embedded cost of long-term debt recommendation of 6.75 percent is a proxy cost of long-term debt based on The Empire District Electric Company's embedded cost of debt as of the true-up period, February 29, 2008, in its last rate case, Case No. ER-2008-0093. Staff will explain its detailed rationale later in this segment of the Report as to why it believes this is an appropriate proxy for a fair and reasonable rate of return for GMO.

Staff's capital structure recommendation is based on GPE's consolidated capital structure, exclusive of the preferred stock and short-term debt, as of September 30, 2008. Schedule 8, contained within Appendix 2 attached to the Report, presents the recommended common equity ratio and long-term debt ratio for GMO's ratemaking capital structure. This capital structure consists of 51.03 percent common stock equity and 48.97 percent long-term debt.

Staff has prepared two attachments and 21 schedules that support its findings and recommendations in the cost of capital area. The attachments contain explanations of the DCF method and the CAPM. These attachments are denoted as Attachments A and B to this Report. The schedules present numerical support for Staff's rate of return recommendation, and are numbered as Schedules 1 through 21. Both attachments and 21 schedules can be found within Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

Rate of return witnesses are mindful of the constitutional parameters that guide the determination of a fair and reasonable rate of return. These parameters were announced by the United States Supreme Court in two seminal cases, *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia* (1923) (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Company* (1944) (*Hope*).[1]

The Supreme Court discussed the following main points in the *Bluefield* case:

1. A return "generally being made at the same time" in that "general part of the country;"
2. A return achieved by other companies with "corresponding risks and uncertainties;" and
3. A return "sufficient to assure confidence in the financial soundness of the utility."

The Court specifically 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

[1] ***Bluefield Water Works & Improv. Co. v. Pub. Serv. Comm'n of West Virginia,*** 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923); ***Fed. Power Comm'n v. Hope Nat. Gas Co.,*** 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943).

> 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.[2]

In the *Hope* case the Court stated:

> The rate-making process, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated . . . that "regulation does not insure that the business shall produce net revenues" . . . 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.[3]

The *Hope* case restates the concept of comparable returns to include those achieved by other enterprises that have "corresponding risks." The Supreme Court also noted in this case that regulation does not guarantee profits to a utility company.

While the legal requirements announced in the *Hope* and *Bluefield* cases have not changed, it is important to recognize that the methodology used to estimate a reasonable rate of return has evolved considerably since these cases were decided over 60 years ago. In fact, two of the most commonly used models in making rate of return recommendations, the DCF model and the capital asset pricing model (CAPM), did not even become a part of mainstream finance until the 1960s. Likewise, capital markets are not confined to regional boundaries when determining the most efficient use of capital.

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[2] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.
[3] ***Hope,*** *supra*, 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

In mainstream finance literature, the DCF model, as used in utility ratemaking, is variously referred to as the dividend growth, Gordon growth and/or dividend discount model. This model was introduced by Myron J. Gordon for cost of common-equity determinations in 1962.[4] The use of this model for stock valuation purposes had been introduced before this time.

The basis for the CAPM was provided in 1964 by William F. Sharpe who received the Nobel Prize in 1990 for much of his work in producing this model.[5] The CAPM is frequently used by investment bankers to estimate the cost of capital for purposes of discounting future cash flows to determine an estimated present value of an enterprise.

It is generally recognized that authorizing an allowed return on common equity based on a utility's cost of common equity is consistent with a fair rate of return. It is for this very reason that the discounted cash flow (DCF) model is widely recognized as an appropriate model to utilize in arriving at a reasonable recommended return on equity that should be authorized for a utility. The concept underlying the DCF model is to determine the cost-of-common-equity capital to the utility, which reflects the current economic and capital market environment. For example, a company may achieve an earned return on common equity that is higher than its cost of common equity. This situation will tend to increase the share price. However, this does not mean that this past achieved return is the barometer for what would be a fair authorized return in the context of a rate case. It is the lower cost of capital that should be recognized as a fair authorized return.

The authorized return should provide a fair and reasonable return to the investors of the company, while ensuring that ratepayers do not support excessive earnings that could result from

[4] Frank K. Reilly and Keith C. Brown, *Investment Analysis and Portfolio Management*, Fifth Edition, The Dryden Press, 1997, p. 438.
[5] Zvie Bodie, Alex Kane and Alan J. Marcus, *Essentials of Investments,* Richard D. Irwin, Inc. 1992, p. 11.

the utility's monopolistic powers. However, this fair and reasonable rate does not guarantee any particular level of return to the utility's shareholders.

Although neither the DCF model nor the CAPM were used for making rate-of-return recommendations during the period in which the *Hope* and *Bluefield* decisions were made, state commissions (including the Missouri Commission) throughout the country have accepted these methodologies for purposes of estimating rates of return for utility ratemaking.

It should be noted that a reasonable return may vary over time as economic conditions, such as the level of interest rates, and business conditions, change. Therefore, the past, present and projected economic and business conditions must be analyzed in order to judge the fairness and reasonableness of a rate of return recommendation.

C. Economic Conditions

Because current economic conditions may impact the rate of return a utility needs to attract investors, it is important for the Commission to consider the past, current and projected capital and economic environment when determining a reasonable authorized ROE for GMO. However, just as one should be cautious about relying too heavily on analyst earnings estimates, one should also use caution when evaluating projected economic conditions. It is most important to try and determine what investors expect when estimating the cost of capital, not necessarily what economists and analysts are projecting. This can be done by evaluating the capital market, the interest rate environment and historical patterns of demand growth.

The world and the U.S. economy are experiencing uncertain times. This makes the estimation of a fair and reasonable cost of capital even a tougher task than normal. Not only is the estimation of the cost of capital difficult, but determining what is reasonable and fair in our current recession is even more difficult. Staff will provide the Commission with what I believe to be the current cost of capital for an electric utility company of at least investment grade credit quality. The challenge in estimating the cost of capital in today's environment comes from the fact that although the risk premiums for certain investments have increased, the risk premium for much safer investments has decreased. There has been an increase in the spread between the cost of low risk securities compared to high risk securities. The Federal Reserve (Fed) has induced much of the lower cost of government securities, at least on the shorter end of the maturity spectrum.

On December 16, 2008, the Fed cut the Fed Funds Rate to between zero and 0.25 percent, which is even below the previous historic low of 1.00 percent under former Fed Chairman Alan Greenspan. This is clearly due to the Fed's concern about the current state of the U.S. economy and what may lie ahead. The Fed normally reserves such aggressive actions for times in which it is concerned about the possibility of a deflationary price environment due to a severe contraction in the economy. In fact, this was the Fed's concern when it reduced the Fed Funds Rate to 1.00 percent under Chairman Greenspan.

Although the current economic and capital market slump picked up considerable speed during the fall of 2008, the Fed began to react to concerns about the economy in the Fall of 2007 (the National Bureau of Economic Research declared in December 2008 that the U.S. has been in a recession since December 2007). Up until September 18, 2007, the Fed had held rates steady at 5.25 percent. However, in response to concerns about a tightening credit market, due in part to problems in the sub-prime market at the time, the Fed reduced the Fed Funds rate by a full 50 (0.50%) basis points on September 18, 2007. Over the remaining part of 2007, the Fed lowered the Fed Funds Rate by 25 basis point increments, on October 31, 2007, and December 11, 2007. The Fed continued to lower the Fed Funds rate through most of the winter and spring of 2008 until they left the rate at 2.25 percent after April 30, 2008. The Fed appeared to not want to lower the Fed Funds rate any further due to concerns about sparking inflation during a period in which certain commodity prices, such as gasoline, were sky-rocketing. However, then came the financial meltdown in which the Fed and the U.S. Treasury began to play a large role in orchestrating bailouts, mergers, acquisitions and allowing some financial institutions to go into bankruptcy, such as Lehman Brothers. The Fed continued to lower the Fed Funds rate by two 50-basis point increments on October 8, 2008, and October 29, 2008, before it made its last cut on December 16, 2008, to arrive at the current rate of zero to 0.25 percent.

According to a recent article in the *Wall Street Journal (WSJ)*[6], during its meeting on December 17, 2008, the Fed stated that "The Federal Reserve will employ all available tools to promote the resumption of sustainable economic growth and to preserve price stability." The Fed also emphasized that it expected interest rates to remain "exceptionally" low for some time, which could help bring down longer-term interest rates. According to the *WSJ* article "The trouble for Fed officials is that while official borrowing rates are very low, interest rates for borrowers with even a modicum of risk remain far above levels of a few months ago, which is squeezing the economy." The impact has been even greater for companies that are of questionable credit quality. For example, according to the same *WSJ* article 'BB'-rated junk bonds were trading at more than "14 percentage points above comparable Treasury bonds; a crushing borrowing cost for many low-rated companies, compared with a spread of less than six percentage points before September."

[6] Jon Hilsenrath, "Fed Cuts Rates Near Zero to Battle Slump: Historic Move Boosts Stocks as Consumer Prices, Housing Starts Drop Sharply; Obama calls for Government Spending Program," *The Wall Street Journal*, December 17, 2008, p. A1 – A2.

Although the Fed tries to influence long-term capital costs through its adjustments to the Fed Funds rate, long-term capital costs do not always respond. Therefore, it is important to analyze the long-term interest rate environment and consider it when recommending a reasonable cost of common equity.

Long-term interest rates, as measured by Thirty-year Treasury Bonds (30-year T-bonds), have dropped to extremely low levels recently. As of January 2009, the 30-year T-bonds averaged 3.13 percent (see Schedule 4-2), which is coming off an all-time low in December 2008 of 2.87 percent. However, because of investors' concerns about the economy during the last quarter of 2008, the average utility bond yields increased to as high as 7.80 percent, as of November 2008. As a result, the spread between the utility bond yields and 30-year T-bond yields hit an historical high of 380 basis points in November 2008 (see Schedule 4-4). The wide spread in November was due in large part to higher average utility bond yields. The increase in utility bond yields to 7.80 percent represents an approximate 200 basis point increase in the yield on public utility bond yields since 2005. Of this 200 basis point increase, 120 basis points have occurred within the last two months, which illustrates the dramatic tightening of the credit market since October 2008. As is typical in many credit-tightening cycles, the spreads between higher quality debt and lower quality debt have increased. Whereas, during a more stable economic environment the spread between A-rated utilities and Baa-rated utilities is typically around 30 basis points, as of November 2008, this spread was 138 basis points. The spread tends to be even smaller when evaluating the difference between an Aa-rated utility and an A-rated utility. This spread is typically around 15 basis points. As of November 2008 this spread was 123 basis points. This results in a spread of 261 basis points between an Aa-rated utility and a Baa-rated utility. This represents a 480 percent increase over the spread in more stable economic times. Consequently, there is a significant capital cost associated with being a less creditworthy company than in more stable economic times.

Although Staff had not received the most recent edition of the Mergent Bond Record at the time of writing this testimony, Staff has reviewed information from Bloomberg and Value Line that indicates that utility bond yields have dropped from the high levels reached in October and November of 2008. According to Bloomberg data, the average 20, 25 and 30-year BBB bond yield was approximately seven percent in December 2008. According to the February 6, 2009 issue of the *Value Line Selection and Opinion*, the yield on BBB-rated utility bonds was 7.04 percent as of January 28, 2009. Based on the 30-year T-bond yield of 3.45 percent as of January 28, 2009, and the BBB utility bond yield of 7.04 percent as of the same day, the spot yield spread was 360 basis points, which is still high, but less than the last couple of months of 2008. Also, it should be noted that Staff does not recommend the use of spot yields making determinations on any specific rate of return adjustments. It is important to evaluate yields over a longer period for purposes of making a responsible rate of return recommendation.

Although the recent tightening of the credit markets has had varying effects on corporations depending on their industry and their specific financial circumstance, according to a January 13, 2009, article in the *WSJ* "Bonds a Bright Spot for Utilities in '08: *Debt Issuance Rose 34% as Investors Shunned Commercial Paper, Stocks,"* the utility industry was able to sell more bonds in 2008 than it had in years. Although these bond issuances occurred throughout the year, this news is still noteworthy because the credit markets had experienced some tightening as far back as the fall of 2007 as the subprime credit issues started to filter into the economy. According to this article, utilities with investment grade credit ratings sold $47 billion of corporate bonds in 2008 compared to $35 billion in 2007 and $26.5 billion in 2006. This compared to a decline in the overall bond market to $645 billion in 2008 from $987 billion in 2007. The article also recognizes that "many utilities were hurt as market valuations tumbled amid investor fears that demand for their services would decline and that they would have difficulties raising the large sums of money that they require, at least at affordable rates." As will be explained later in this section of Staff's Cost of Service Report, the decline in utility stock prices due to concerns about future demand is a fundamental principle in estimating the cost of common equity when performing a DCF analysis. One of the companies mentioned in this article, Progress Energy Inc., is a part of the proxy group Staff used to estimate the cost of common equity for GMO in this case. On January 8, 2009, Progress Energy issued 10-year bonds at a coupon rate of 5.3 percent. Consequently, it appears that the cost of capital for utility companies is returning to levels prior to the credit crisis. Another issue mentioned in the article is that, although the spreads over U.S. Treasury's for recent utility bond issuances have been high, much of these high spreads can be attributed at least in part to the extremely low rates on U.S. Treasury bonds. Consequently, while utility bond risk premiums over U.S. Treasury bonds have increased, because yields on U.S. Treasury bonds have decreased dramatically, this doesn't necessarily mean that the overall cost of capital to utilities has increased that much.

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the January 16, 2009, issue of *The Value Line Investment Survey: Selection & Opinion*, for the fourth quarter of 2008 the Dow Jones Industrial Average (DJIA) declined 19.1 percent, the Standard & Poor's (S&P) 500 declined 22.6 percent, the

NASDAQ Composite Index (NASDAQ) declined 24.3 percent, and the Dow Jones Utility Average (DJUA) declined 13.5 percent. According to the same publication, for the twelve months ended December 31, 2008, the DJIA declined 33.8 percent, the S&P 500 declined 38.5 percent, the NASDAQ composite declined 40.5 percent, and the DJUA declined 30.4 percent.

As can be seen from the above, stock indices have suffered major declines in the past quarter, and year. While an initial reaction to a significant decline in stock prices may be to assume that the cost of capital has significantly increased, one must also consider the reasons why stock prices have declined. It appears that investors are concerned about a global slowdown in the economy, which would impact the expected return an investor would receive from growth in stock prices. Therefore, the required return may now be more concentrated in the dividend yield investors expect to receive. Staff will discuss this in more detail later in its testimony when explaining its cost of common equity recommendation. Another thing to consider about the above stock market results is that while the DJUA had declined with the rest of the market in 2008, the DJUA had performed quite well over previous years. According to a January 9, 2009, BMO Capital Markets report, "Electric Utilities: 2008 in Review; Outlook for 2009," the DJUA returned 54.6% for the period 2003 through 2008 while the S&P 500 returned 2.7%, the DJIA returned 5.2% and the NASDAQ returned 18.1% for the same period. Consequently, utility stocks, as measured by the DJUA, had been significantly outperforming the rest of the market for the past five years.

Although the DJUA is one of the more widely published utility indexes, it should be used with caution for purposes of drawing inferences about possible trends in regulated utilities' cost of capital because many of the companies in the DJUA have non-regulated operations that at least contribute to their performance. In fact, the Edison Electric Institute (EEI) does not consider a majority of the companies in the DJUA to be "regulated utilities," which is one of the criteria Staff used to select its comparable companies in this case. However, three of Staff's comparable companies are included in the DJUA and are classified as "regulated utilities" by EEI. Regardless, Staff does not consider the DJUA as a good proxy group for KCPL. However, comparing utility index results to the rest of the stock market can provide insight on the value being placed on utility stocks in general.

Utility indices can also vary in their results. For example the Value Line Utilities Group, which is composed of "utility" companies followed by Value Line, decreased by 15.9 percent for the fourth quarter of 2008, compared to the 13.5 percent decrease for the DJUA. The Value Line Utilities Group decreased 32.7 percent for all of 2008 compared to the DJUA's decrease of 30.4 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation. However, during 2008 it appears that the DJUA and the Value Line Utilities Index have performed similarly.

It is also worthwhile to review some economic indicators for purposes of evaluating the reasonableness of a rate of return recommendation in this case. Although a reasonable DCF analysis captures investors' expectations about future economic conditions, investors will review some of this information to arrive at their own conclusion about a fair price to pay for utility stocks in today's environment.

The Value Line Investment Survey: Selection & Opinion, November 21, 2008, estimates inflation to be 4.5 percent for 2008, 1.3 percent for 2009 and 2.5 percent for 2010. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009-2019*, January 2009, indicates an inflation rate of 4.4 percent for 2008 and estimates inflation to be 0.5 percent for 2009 and 1.4 percent for 2010 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury Bills, are estimated to be 1.6 percent in 2008, 1.5 percent in 2009 and 2.7 percent in 2010 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.4 percent in 2008, 4.2 percent in 2009 and 4.5 percent in 2010.

The most recent weekly rate for three-month U.S. Treasury Bills was 0.19 percent (see Schedule 5). The most recent weekly rate for long-term treasury bonds was 3.45 percent (see Schedule 5).

GDP is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to increase by 1.4 percent in 2008, decrease by 0.9 percent in 2009 and increase by 2.5 percent in 2010. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009-2019*, stated that real GDP increased 1.9 percent in 2008 and is expected to decline by 1.9 percent in 2009 and increase by 0.4 percent in 2010 (see Schedule 5).

The Value Line *Investment Survey: Selection & Opinion*, January 9, 2009, stated the following in its Economic and Stock Market Commentary:

> **The United States and other countries are caught in the grip of what will likely be a long and painful recession.** This nation's economic difficulties—which have been apparent in housing for more than a year and in other areas for a shorter span of time—worsened noticeably last quarter. That period, which ended with one of the poorest holiday shopping seasons on record, may have seen U.S. gross domestic product tumble by 5%, or so.

> **At least two more quarters of sharp economic reversals look to be ahead of us.** True, a contraction in business activity of such mammoth proportions, as we probably saw last quarter, may have been a one-time affair. However, even if the worst of the downturn is behind us—due to the unprecedented governmental steps taken in 2008 and the massive monetary infusions by the Federal Reserve—there would seem to be enough cumulative weakness around in housing, autos, retailing, and industrial activity to almost ensure that GDP will decline by 2% to 4% in the first half of 2009.
>
> **Any business recovery in 2009 may arrive late and be selective, in our view.** Our sense is that the fiscal and monetary moves undertaken last year and the prospective federal government recovery plans likely to be forthcoming will lessen the severity and duration of the recession in select areas, such as infrastructure building and possibly even housing. However, the hoped-for second-half recovery is a bit conjectural at this time. Indeed, even if all goes well, any second-half growth may be capped at 1% to 2%.
>
> **While there is some room for optimism on the economy,** likely further increases in joblessness and the prospective additional declines in home prices do not augur well for the improvement in consumer spending that is needed to revive the economy. A partial offset to the above is likely to be the gains in disposable income that should evolve from the recent declines in heating oil, gasoline, and food costs. Once other sectors of the economy start to stabilize, the lower inflation should provide some help to spending.
>
> **The investment picture remains muddled.** Equities are still range bound, reflecting the tough business outlook, on the one hand, and the possibility that last year's dismal stock market performance may have partially taken these hard times into account, on the other hand.
>
> **Conclusion:** We think this tug of war will ultimately be resolved in favor of the bulls, assuming the economy starts to stabilize during the first half of 2009. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

Staff believes that the economic and capital market environment of the past few months reflects a change in investors' expectations, which may have caused a slight increase in the cost of capital to utilities, at least temporarily. While it will be apparent from the higher dividend yields reflected in the DCF model that risk premiums have increased, close scrutiny should be given to the determination of a reasonable growth rate that should accompany this increased risk premium. If investors are fearful that the economy is entering a long recession, or at the very least a long period of slow growth, then the expected growth rate in the DCF model should reflect this. If equities' analysts have been slow to update their 5-year estimated earnings per share growth rates to reflect a slowing economy, then using these higher growth rates along with higher dividend yields will result in an unreasonably high estimated cost of common equity. The likely effect of using the capital asset pricing model (CAPM) without giving thought to the reasonableness of assumptions made will cause an unreasonably low estimate of the cost of common equity. As long as one uses reason and logic as to the assumptions used in the models, the end-result should be reasonable.

D. Determination of the Cost of Capital

A utility's cost of capital is usually determined by evaluating the total dollars of capital for the utility company at a specific point in time, i.e., the end of the test year or update period. This total dollar amount is then apportioned into each specific capital component; i.e. common equity, long-term debt, preferred stock and short-term debt. A weighted cost for each capital component is determined by multiplying each capital component ratio by the appropriate embedded cost or by the estimated cost of common equity component. The individual weighted costs are summed to arrive at a total weighted cost of capital. This total weighted average cost of capital (WACC) is synonymous with the fair rate of return for the utility company.

A company's authorized WACC is considered a just and reasonable rate of return under normal circumstances. From a financial viewpoint, a company employs different forms of capital to support, or fund, the assets of the company. Each different form of capital has a cost, and these costs are weighted proportionately to fund each dollar invested in the assets. Assuming that the various forms of capital are within a reasonable balance and are valued correctly, the resulting total WACC, when applied to rate base, will provide the funds necessary to service the various forms of capital. Thus, the total WACC corresponds to a fair rate of return for the utility company.

E. Capital Structure

The capital structure the Staff used for this case is GPE's capital structure on a consolidated basis, exclusive of preferred stock and short-term debt, as of the end of the updated test year period in this proceeding, September 30, 2008. Schedule 8 presents GPE's capital structure and associated capital ratios for long-term debt and common equity. The resulting ratemaking capital structure consists of 51.03 percent common stock equity and 48.97 percent long-term debt.

Staff chose to remove the GPE's preferred stock from the capital structure because this is an embedded cost and Staff is not proposing the consolidation of embedded costs for purposes of this case. Consequently, because GPE's preferred stock and debt were issued before the acquisition of the Aquila Missouri electric utility properties, Staff believes it is appropriate to exclude the preferred capital from its recommended rate of return for GMO.

It is appropriate to use GPE's capital structure, exclusive of preferred stock and short-term debt, for GMO's ratemaking capital structure because this represents the current financial risk associated with GMO's operations. GMO's credit rating is based on the consolidated credit profile of GPE. For example, in S&P's September 19, 2008 research report on GMO, S&P analyzes GPE's consolidated financial ratios when providing its opinion on GMO's creditworthiness. In fact, GPE did not file separate GMO financial statements with the

SEC when it filed its Form 10Q Filing for September 30, 2008. GMO's financial results are embedded in GPE's consolidated financial statements.

Although GPE's capital structure will be that analyzed by investors going forward when determining a required yield on debt funds used by GPE for GMO's operations, it is the capital structures of the companies that previously owned GMO's utility operations that drove the required return on the debt contained in GMO's current embedded cost of long-term debt. In fact, some of this debt wasn't even issued under Aquila's ownership. Some of the debt assigned to GMO's L&P division was issued while these operations were a part of the stand-alone, publicly-traded entity, St. Joseph Light and Power Company (SJL&P). Therefore, GMO is carrying debt issuances that were associated with business and financial risks that were in effect at the time SJL&P issued this debt. One could argue that the ratemaking capital structure for the instant rate case should take both Aquila's and SJL&P's capital structures into consideration when evaluating the appropriateness of Staff's proposed ratemaking capital structure. However, the problem with this type of evaluation is not only would one be evaluating capital structures for two companies, it would be evaluating capital structures for two companies during different capital, business and economic conditions. Ideally, a company will adjust its capital structure to achieve the lowest cost of capital for the environment in which they operate. Also, one has to realize that because the recommended ROE is based on an estimate of the current cost of common equity, it is important to use a current capital structure that reflects the current amount of common equity in the capital structure.

Notwithstanding the above, Staff also notes that the ratemaking capital structure used in Aquila's last rate case, Case No. ER-2007-0004, was fairly close to Staff's proposed capital structure in this case. Staff's rate of return recommendation in that case was based on capital structure containing 47.5 percent equity and 52.5 percent long-term debt. However, Staff also notes that Aquila's historical capital structures had on average been more leveraged than in the most recent two years prior to GPE's acquisition of the GMO properties (see Schedule 6-2).

Although, GPE's overall risk profile has been impacted by its divestiture of Strategic Energy and its acquisition of the GMO properties, GPE's current capital structure is reasonable and consistent with its past capital structures. Although, GPE's common equity ratio averaged 47.16 percent over the most recent five years, for the most recent three years the average was 50.22 percent, which is only slightly lower than the common equity ratio as of September 30, 2008. In fact, at least in the long-term, the financial risk of GPE's consolidated capital structure can be managed consistent with that of a pure-play regulated electric utility since GPE has divested its non-regulated subsidiary and acquired a regulated subsidiary. However, in the short-term investors will assign risk to GPE based on the risk of integrating Aquila's electric utility operations into GPE. It is for this reason that Staff did not assign any weight to its company-specific cost of common equity estimate in this case. Staff recommends the Commission not give any weight to the GPE company-specific cost of common equity because to do so would allow for higher costs to be passed through to ratepayers because of the risks associated with the acquisition. Also, due to the timing of GPE's announced 50 percent dividend reduction made on February 10, 2009, Staff was not able to reflect this new information in this Cost of Service Report or in the cost of service report filed in the KCPL rate case, Case No. ER-2009-0089. Regardless, Staff did not believe a GPE company-specific cost of common equity estimate should be given any weight because of the effect that the acquisition of the GMO properties may have had on GPE's stock price. However, the recent action by

GPE solidifies that investors may have considered GPE's current dividend to be at risk of being reduced because GPE's dividend yield was quite high at the time Staff performed its analysis.

It is also worthy to note that Staff's proposed ratemaking capital structure in this case is similar to The Empire District Electric Company's common equity ratio of 50.82 percent as of the test year in its most recent rate case, Case No. ER-2008-0093. Staff believes this supports using a common equity ratio of around 50 percent for GMO's utility properties. However, careful consideration should be given to the cost of debt used with this capital structure.

F. Embedded Cost of Debt

In the prior Aquila rate case, Case No. ER-2007-0004, Staff witness David Parcell[7] accepted the costs of debt used by Aquila for its Missouri electric utility divisions. Staff witness Parcell did not accept the capital assignment process or the methodology used to make adjustments to the cost of debt, he simply accepted the overall estimate. In Aquila's two rate cases prior to Aquila's most recent case, Case Nos. ER-2005-0436 and ER-2004-0034, Staff witness Murray used Aquila's consolidated embedded cost of debt, but made adjustments to this debt. In Case No. ER-2004-0034, Staff simply excluded the debt that was issued after Aquila had its corporate credit rating downgraded to below investment grade. In Case No. ER-2005-0436, Staff used the cost of an Empire debt issuance that was issued around the same time as the Aquila non-investment grade debt issuance and included this with the rest of Aquila's debt issued prior to its credit rating being downgraded to "junk" status. Aquila's failed non-regulated investments have caused the need for both the company and other parties to make judgments on what the cost of debt might have been if MPS and L&P had been owned by a

[7] Staff hired a consultant in the last rate case

company with at least an a BBB credit rating. As time has passed and ownership structures have changed, the embedded cost of debt for MPS and L&P has become even less based on reality.

As a result of the above, Staff recommends the use of a hypothetical embedded cost of long-term debt for GMO. Staff proposes the use of The Empire District Electric Company's (Empire) embedded cost of long-term debt from its last rate case, Case No. ER-2008-0093 as of the true-up date, February 29, 2008. This embedded cost of long-term debt was 6.75 percent. Staff believes the use of Empire's embedded cost of debt is appropriate because the risk profile of Empire and GMO are fairly similar, Empire's operations are predominately regulated operations, most of which are confined to Missouri, and Empire's most recent ratemaking capital structure is similar to that of GMO's parent company, GPE.

G. Cost of Common Equity

In order to estimate the cost of common equity for GMO, Staff performed a comparable company cost of common equity analysis of eleven electric utility companies. Staff estimated GMO's cost of common equity using the constant-growth DCF (explained in detail in Attachment A), the CAPM (explained in detail in Attachment B) and a multi-stage DCF methodology (explained later in this section of the Cost of Service Report). In addition, Staff reviewed some other indicators to test the reasonableness of its recommendation. Staff will discuss these in more detail later in this segment of the report.

Staff started with a list of 65 market-traded companies classified as electric utility companies by Value Line (see Schedule 9). This list was reviewed for the following criteria, to develop a proxy group comparable in risk to GMO:

1. Classified as an electric utility company by Value Line;
2. Stock publicly traded: this criterion did not eliminate any companies;

3. Classified as a regulated utility by EEI or not followed by EEI: this criterion eliminated thirty companies;
4. At least 70 percent of revenues from electric operations or not followed by AUS: this criterion eliminated fourteen additional companies;
5. Ten year Value Line historical growth data available: this criterion eliminated two additional companies;
6. No reduced dividend since 2005: this criterion eliminated four additional companies;
7. Projected growth available from Value Line and IBES: this criterion eliminated five additional companies;
8. At least investment grade credit rating: this criterion did not eliminate any additional companies; and,
9. Company-owned generating assets: this criterion did not eliminate any additional companies.

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

Staff performed its traditional constant-growth DCF analysis in this case, but because of uncertainties in the market and unsustainable projected earnings growth rates, Staff decided to rely primarily on a multi-stage DCF analysis to arrive at its recommended ROE. Because of the dramatic events in the economy and the market over the last few months, risk premiums have increased. However, at the same time risk-free rates have decreased, so the overall cost of capital hasn't changed significantly. This has become apparent with the recent return of utility bond yields to pre-October 2008 levels. Staff believes the risk premiums have increased because investors have become more pessimistic about the future growth of the economy and there has been very little good news to change investors' minds about the growth potential of the economy. Although the 2008 fourth quarter GDP didn't contract as much as some had expected, it did decrease by 3.8 percent and this followed a contraction in the third quarter of 0.5 percent, which means that the economic downturn now meets the textbook definition of a recession, which is two consecutive quarters of contraction in GDP. Staff does not believe that equities analysts' earnings projections are sustainable, especially considering the state of the economy.

GPE's executive officers recently acknowledged during their 2008 third quarter earnings conference call that they believed the economy was going to impact their revenue growth. Terry Bassham, Executive Vice President and Chief Financial Officer, indicated the following:

> From a revenue perspective, we aren't looking for much in the way of weather-normalized retail demand improvement next year. The economy in our service territory is sluggish and we are looking for KCP&L demand to say about flat, with GMO growing at about the same rate as this year. That should put combined weather-normalized retail sales growth at about half a percent for the year. As we look at 2010 and 2011, we do see a bit of demand improvement at KCP&L but still below the 2% growth rates we'd seen historically. We expect GMO's growth to significantly be below the 2003-2007 average of 2.5% - 3.0% as well. On a consolidated basis in 2010 and 2011, retail sales will grow at around 1% or so.

Even normal growth rates for KCPL and GMO are in the two to three percent range and GPE is expecting these growth rates to be even lower over at least the next three years because of the sluggish growth in the economy. If investors are expecting a protracted period of slow growth in the national economy, then one would expect the growth rate for utilities throughout the country to be lower than their historical growth rates. Staff believes these lower growth projections are impacting stock prices in general and utility stock prices in particular. Investors' lower growth expectations must be factored into a cost of common equity analysis in order for such analysis to be reliable.

Because Staff decided to perform a multi-stage DCF model analysis after deciding its traditional constant-growth DCF analysis and its CAPM analysis were not reliable in this case, it will explain the latter two analyses first.

The first step Staff performed in its constant-growth DCF analysis was to estimate a growth rate. Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected DPS, EPS and BVPS growth rates for the comparables. Schedule 11-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 11-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 11-3 presents the averages of the growth rates shown in Schedules 11-1 and 11-2. As can be seen from these schedules, the historical growth rates have been volatile. Because of this volatility, Staff hesitated to give much weight to the historical growth rates in estimating investors' expectations of future growth for the proxy group. Consequently, Staff analyzed projected growth rates to determine if these growth rates might be a reliable proxy for investors' expectations of future long-term growth in the proxy group's stock price.

Staff analyzed the projected DPS, EPS and BVPS as estimated by the Value Line analyst over the next five years for each company (see Schedule 12). As can be seen from this schedule, the growth rate projections for these same indicators are also widely dispersed among the comparable companies. Staff also compared IBES analyst earnings estimates to that of the Value Line earnings estimates on Schedule 14. As can be seen from this schedule, the projected growth rates range from two percent to 13.63 percent, and average in the six to seven percent range. Staff does not believe these growth rates are sustainable, not to mention the fact that they don't make much sense in the current economic environment. Staff does not believe these growth rates should be given much weight in its constant-growth DCF analysis. Although Staff does not believe it is prudent to rely on either the historical or projected growth rates to estimate a growth rate for its constant-growth DCF model analysis, Staff nevertheless plugged in a growth rate of four to five percent because this gives some consideration to some of the high estimated EPS growth rate estimates, but tempers these growth rates because they are not sustainable. Staff emphasizes that it did not scrutinize the selected growth rates. If anything, a four to five percent growth rate is too high of a growth rate to expect as a constant-growth rate for the electric utility industry. Staff is simply using these growth rates to show a result for informational purposes only. Staff decided to use a multi-stage analysis after it reviewed the data from its traditional constant-growth DCF analysis. Consequently, Staff believed it was important to show the data it analyzed to make this decision. Just as Staff does not recommend the Commission give any weight to the GPE-specific DCF results, Staff does not recommend giving the traditional constant-growth DCF analysis any weight. As will be discussed when describing Staff's multi-stage DCF analysis, Staff believes that a sustainable perpetual growth rate is lower than four to five percent.

The next step was to calculate an expected yield for each of the comparables. The yield term of the constant-growth DCF was calculated by dividing the amount of DPS expected to be paid over the next 12 months by the market price per share of the firm's stock. Because of the recent volatility in the stock market, it is important to ensure the selection of stock prices that reflect investors' current expectations of the business and economic climate. Because investors' expectations began to change in October 2008 due to the credit crisis, Staff believes this is the appropriate starting point. Staff believes it is important to capture all monthly stock prices since October to reflect investors' ongoing analysis of the current economic conditions and the impact it is having on their expectations of future returns and the risk of these returns. Consequently, Staff chose to use stock prices for the past four months to determine an average market price for each of the comparables. This averaging technique minimizes the effects on the dividend yield which can occur due to the volatility in the stock market. Schedule 15 presents the average high / low stock price for the period of October 1, 2008, through January 31, 2009, for each comparable. Column 1 of Schedule 16 indicates the expected dividend for each comparable over the next 12 months as projected in the most recent Value Line report. Column 3 of Schedule 16 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected average dividend yield for the comparables of 5.45 percent. Considering the Commission's position regarding the quarterly-compounding of dividends expressed in its Report and Order in the most recent Union Electric rate case, Case No. ER-2008-0318, it is important to note that this dividend yield has not been adjusted for quarterly compounding. Staff is attempting to estimate investors' expectations and because the Value Line quoted dividend yield does not reflect quarterly compounding, Staff is not convinced that investors' analyze the expected dividend yield on a quarterly-compounded basis. Staff will discuss another reason for not compounding quarterly when it explains its multi-stage DCF analysis.

As shown on Schedule 16, the average cost of common equity based on the projected dividend yield and a growth rate range of four to five percent is 9.40 percent to 10.40 percent. Staff believes the use of a four to five percent constant growth rate range is optimistic considering current economic conditions. Staff does not recommend the Commission authorize an ROE based on Staff's constant-growth DCF analysis in this case.

Staff performed a CAPM cost of common equity analysis on the comparables. The CAPM requires estimates of three main inputs, the risk-free rate, the beta and the market risk premium. For purposes of this analysis, the risk-free rate Staff used was the yield on Thirty-year U.S. Treasury Bonds. Staff determined the appropriate rate to be the average yield for January 2009. The average yield of 3.13 percent was obtained from the St. Louis Federal Reserve website.

For the second variable, beta, Staff used Value Line's betas for the comparable group of companies. Schedule 17 contains the appropriate betas for the comparables.

The final term of the CAPM is the market risk premium (R_m - R_f). The market risk premium represents the expected return from holding the entire market portfolio, less the expected return from holding a risk-free investment. Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds. However, just as Staff warned before the recent capital market issues ensued, these risk premium estimates may not reflect the current risk premiums implied in the valuation of stock prices. Consequently, the reliability of cost of common equity results obtained from performing a CAPM analysis or risk premium analysis is heavily dependent on the estimated risk premium used to determine the cost of common equity. Although risk-free rates have dropped in the last couple of months, risk premiums have also increased in recent months. If the inputs in the CAPM analysis are not adjusted to reflect the current uncertain capital and economic environment, then the CAPM will yield illogical results. Because the estimation of implied equity risk premiums is often done by using some variation of the DCF model, Staff believes any such attempt in this case to estimate the equity risk premium for purposes of the using the CAPM model will only be as reliable as the DCF analysis used to estimate this equity risk premium. If the DCF analysis doesn't appear to be reliable, then any risk premiums estimated using a DCF analysis will be unreliable. Consequently, Staff focused its time and effort on performing a multiple-stage DCF analysis to provide what it believes to be the most reliable results in the current capital and economic environment. Nevertheless, Staff performed a CAPM analysis to show the impact that extremely low risk-free rates have had on CAPM results using the historical earned return risk premiums using both arithmetic and geometric averages.

The first risk premium Staff used was based on the long-term, arithmetic average of historical return differences from 1926 to 2007, which was 6.50 percent. The second risk premium used was based on the long-term, geometric average of historical return differences from 1926 to 2007, which was determined to be 4.90 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2008 Yearbook.*

Schedule 17 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the long-term arithmetic average risk premium and the long-term geometric average risk premium produces estimated costs of common equity of 7.91 percent and 6.73 percent respectively. Staff does not believe these current CAPM results are reliable indicators of the cost of common equity for the proxy group and therefore, GMO. According to the February 6, 2009, issue of the *Value Line Selection & Opinion*, a BBB long-term utility bond yield was 7.04 percent as of January 28, 2009. Because the CAPM result using the geometric average is below this bond yield and the CAPM result using the arithmetic average is less than 100 basis points above this bond yield, Staff does not believe a CAPM analysis based on historical risk premiums and current risk-free rates is reliable.

Because of Staff's concerns about the reliability of both its constant-growth DCF analysis and CAPM analysis in this case, Staff chose to perform a multiple-stage DCF analysis. Although other rate of return witnesses have used two-stage and multiple-stage DCF analyses in past rate cases in which Staff sponsored testimony, Staff did not believe it was then necessary because of the stability of the economy, the capital markets and expected growth rates for regulated electric utilities that seemed to be sustainable. However, that is not the situation now. Therefore, Staff believes it is appropriate to use a multiple-stage DCF analysis in order to arrive at a more reliable estimated cost of common equity.

Multiple-stage DCF methodologies are usually intended for industries and/or companies that are in the early stages of their growth cycles. In these instances, these companies/industries may have growth rates that exceed their cost of capital. In such situations, the use of a constant-growth dividend model does not provide logical results because, in order for the dividend valuation model to work, the growth rate must be less than the cost of capital. This, of course, assumes that the company is even paying a dividend in its early development stage. Because the utility industry is a mature industry, this is not a problem, and the constant-growth DCF is usually appropriate. However, if the industry and/or the economy are going through a period of transition, then a multiple-stage DCF analysis becomes appropriate. However, there may be sectors within the utility industry that are not as largely impacted by changes in the economy. For example, although Staff has not performed a cost of capital study on the natural gas distribution industry since the credit crisis, the constant-growth DCF may still provide the most reliable estimated cost of common equity for this industry. Many finance textbooks have used the utility industry as an example for an appropriate situation to use the constant-growth DCF model, so this methodology is still sound as long as the capital and economic environments are fairly stable and the industry is mature and stable. [8][9]

Because of the factors discussed above, Staff believes a multi-stage DCF analysis will provide the most reliable cost of common equity estimate, as long as reasonable growth rates are used at the various stages in the analysis. As with the constant-growth model, it is not the model alone that allows for reliable results, it is the reasonableness of the inputs that provide reliable results. Although the reasonableness of early-stage estimated growth rates are important in a multi-stage DCF analysis, the perpetual growth rate used will be the primary driver of the final cost of common equity estimate. While a DCF analysis of companies/industries in the early stages of their growth cycle, i.e. supernormal growth companies, may use GDP as an estimate for the perpetual growth rate, this is not reasonable for mature industries that are simply going through transition impacted by construction cycles and/or economic uncertainty. It is entirely reasonable to expect that utility companies will return back to a growth rate consistent with their real growth plus a factor for inflation. This should cause electric utility companies to settle on a perpetual growth rate of around three percent, which Staff will support later in this section of the Cost of Service Report.

Although Staff believes equities analysts' earnings growth rates may not be factoring in current economic conditions and the effect they may have on future electricity demand, Staff does realize that many electric utility companies are involved in a significant amount of construction that may improve their earnings when these projects are reflected in rates. Therefore, Staff chose to give full weight to the analysts' earning growth estimates for the

[8] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 195-196.
[9] 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.

first five years of its DCF analysis and partial weight to these analyst growth rates in years six through ten. However, Staff does not believe these earnings growth rates are sustainable. For this reason, Staff chose to rely on projected electricity consumption growth and an inflation factor to estimate investors' expectations of long-term sustainable growth for an electric utility company. Staff relied on the Energy Information Administration's projection of long-term electricity consumption of approximately 0.9 percent for the period 2007 through 2030 for all sectors of the economy[10] and added the Congressional Budget Office's projected inflation of 2.2 percent over the long-term[11] to arrive at a perpetual growth rate of 3.1 percent, which is a reasonable long-term growth rate to expect for the electric utility industry. In fact, based on the current yields of long-term treasuries, the estimated inflation Staff uses is higher than the return investors are requiring for inflation based on the spread between nominal treasury bonds and treasury inflation protected securities (TIPS). For example, the yield for a 20-year nominal treasury bond averaged 3.46 percent in January 2009, whereas the yield on the 20-year TIPS bond averaged 2.46 percent in January 2009. This implies that investors are only requiring a 1 percent return for the prospects of inflation over the next 20 years. The 2.46 percent yield on the 20-year TIPS is the required real return, which is often considered as a proxy for investors' expectations of real GDP growth for the same period. If Staff had used a one percent inflation factor, then the long-term perpetual growth rate would have been 1.9 percent.

Actually, a perpetual growth rate of two to three percent appears to be consistent with long-term expected growth before the recent downturn in the economy. According to an article in the October 2004 issue of *Public Utilities Fortnightly,* "The Dividend Yield Trap," regulated

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[10] "2009 Annual Energy Outlook," p. 4, *Energy Information Adminstration*

[11] "The Budget and Economic Outlook: Fiscal Years 2009 to 2019," Table B-1, *Congressional Budget Office.*

electric utilities long-term growth expectations should not be much more than one to three percent. The article goes on further to state that the average long-term growth rate of 4.6 percent for the component utilities of the Lazard Core Utility Index was too optimistic and a "long-term growth proposition is closer to two to three percent, and then only if the industry is able to successfully execute on cost-cutting initiatives. In this regard, it is worth noting that during the past 30 years the industry has achieved a compound average growth rate of only one percent." These lower perpetual growth rates are also consistent with many of the perpetual growth rates used by equities analysts' when performing discounted cash flow analysis on utilities, including GPE. Staff believes that this information further supports its selection of a perpetual growth rate of 3.1 percent and if anything, is on the high side considering current economic uncertainties.

Instead of reducing the 5-year analyst growth rate estimates down to the perpetual growth rate in year six (this is the assumption in most 2-stage DCF analyses, which results in a lower cost of equity estimate), Staff decided to allow for a gradual decline from years six through ten and then applied the perpetual growth rate starting in year eleven because projecting company-specific growth rates past this time is futile.

When performing its constant-growth DCF analysis, Staff does not make the assumption that next year's dividend will grow at the rate of projected earnings growth because Staff does not believe this reflects investors' expectations. However, for purposes of performing its multi-stage DCF analysis in this case, Staff made this simplifying assumption because the dividend yield is not one of the components of a multi-stage formula. The dividend yield is embedded in the expected growth of dividends and the present value of the dividends equaling the current stock price of the company. This calculation is equivalent to determining the internal rate of return (IRR) for a possible investment. The IRR is the discount rate that makes the present value of all future cash flows equal to cost of the initial investment. In most cases, if the IRR is higher than the cost of capital, then the company will make the investment. As with many of the methodologies used to estimate the cost of common equity for utility companies in rate case proceedings, this model was adapted to solve for the equity investors' required rate of return. There are many situations in which cash flows are discounted to determine a current value of a proposed investment. For example, investment advisors discount expected future cash flows of a possible investment by the cost of common equity of the operation in order to provide an opinion on the "fair value" of a proposed investment. Staff will explain later why it believes its estimate of the cost of common equity using a multi-stage DCF methodology is supported by investment advisors that have estimated the cost of common equity for purposes of GPE's acquisition of the GMO properties.

Staff provides its multi-stage DCF analysis recommendation on Schedule 18. Schedule 18 shows the proxy group's overall average cost of common equity and Staff's recommended range based on this average. Staff does not recommend an adjustment to the estimated proxy group's cost of common equity because GMO's credit rating is similar to that of the proxy group. This implies that the risk profile of the proxy group and GMO are similar. Staff recommends an estimated cost of common equity range of 9.25 percent to 10.25 percent based on its multi-stage DCF analysis, with a point estimate of 9.75 percent. Staff recommends the Commission's authorized cost of common equity be based on the point estimate, but believes anywhere within this range is reasonable.

Staff does not believe its multi-stage DCF analysis should be adjusted upward for quarterly compounding as the Commission requested in its recent Report and Order in

Case No. ER-2008-0318. Estimating the cost of common equity necessarily involves making certain simplifying assumptions. In this case, Staff assumed that investors would receive higher dividends in the near future at the rate of earnings growth when in reality this will not happen. If Staff were to assume that investors would be able to reinvest these extra dividends that they will not receive, then this would only inflate the estimated cost of equity. For example, although Ameren is currently paying a dividend of $2.54 and according to Value Line is not expected to increase this dividend for the next five years, Staff's multi-stage DCF analysis made the assumption that this dividend would grow from years one through five at a rate of 4.50 percent per year. If Staff discounted the real dividends investors expect to receive over the next five years by its recommended cost of equity of 9.75 percent, this would result in a present value for these dividends of $9.69. If Staff discounts the dividends assumed in its multi-stage DCF analysis using the same discount rate, the result is a present value of $10.91 for these dividends. Since the second present value calculation results in a higher value, this would require a higher discount rate to match the actual dividends that investors will receive. Over this 5-year period, the discount rate (cost of common equity) has to be increased to 14.42 percent in order to achieve a present value of $9.68 for the higher dividends that most likely will not be received in the next five years. The magnitude of this difference will get much smaller over a longer period.

Staff believes its cost of common equity recommendation is reasonable because its inputs are reasonable, but Staff is aware of other cost of common equity estimates used by investment banks that advised GPE and Aquila on GPE's acquisition of Aquila (now known as GMO) that further support the reasonableness of Staff's recommendation. In fact, because these cost of common equity estimates were provided by consultants hired by GPE and Aquila for a purpose other than a rate case, Staff believes this further illustrates the unreasonableness of GMO's witness' estimated cost of common equity in this case and in past KCPL and Aquila cases.

Staff reviewed the opinions of GPE and Aquila's financial advisors (GPE received opinions from Credit Suisse Securities (USA), LLC ("Credit Suisse") and Sagent Advisors, Inc. ("Sagent"); Aquila received opinions from Blackstone Advisory Services L.P. ("Blackstone"), Lehman Brothers, Inc. ("Lehman Brothers") and Evercore Group L.L.C. ("Evercore") provided in its SEC Form S4 Filing (prospectus) filed on June 26, 2007. Although the financial advisors' opinions were summarized in the prospectus, Staff was unable to analyze the details of the costs of common equity and the overall weighted average costs of capital used by these financial advisors. Staff issued Staff Data Request No. 0113 in order to attempt to examine the assumptions made by the financial advisors in more detail, but KCPL objected to this data request as irrelevant and asserted that this information was not in its possession, custody or control. Staff considers this information relevant because the determination of discount rates used for valuation purposes is based on the financial advisors' opinions on the cost of capital, which is the very thing we are attempting to estimate when recommending an appropriate rate of return in a rate case. Although Staff is not aware of any resolution on the status of the data requested, Staff believes this information would have been helpful in more fully understanding the estimates made by the financial advisors, Staff believes it was still important to review the publicly available information provided to investors in order to test the reasonableness of both its recommendation and that of other parties.

Staff believes just the mere fact that the investment banks were estimating the cost of common equity for purposes of determining a fair value for a pure-play utility company should suffice for justifying the relevance of this information, but there are other reasons Staff believes this information is relevant, especially to the instant proceeding. First, the analysis done by the investment banks involves the operations of both Great Plains Energy's KCPL operations and GMO's electric utility operations, which are both the subject of rate cases before this Commission. Second, the analysis done by these investment banks involves estimating the cost of common equity using some of the same models used in estimating the cost of common equity in utility rate proceedings. For example, many investment banks use the CAPM to estimate the cost of common equity to determine an appropriate discount rate. Third, investment banks do a comparable company analysis to arrive at what they believe to be a "fair value." The number and type of companies can be reviewed to determine the reasonableness of the witnesses' comparable groups. Fourth, because this process involves estimating future cash flows from the utility operations, it can be evaluated to determine the reasonableness of certain estimated growth rates used in the witnesses' DCF analysis. This is true for both near-term growth rates and perpetual growth rates. Finally, the Commission can review this information to determine if investment advisors discount cash flows on an annual basis or on a quarterly basis. There may be additional information in these analyses that may be useful in testing the reasonableness of recommendations in this case, but Staff cannot identify that information because it only has access to the information provided in the prospectus.

Unfortunately, most of the financial advisors' publicly-available cost of capital estimates are based on their overall WACC, which is calculated slightly differently than it is in utility regulatory rate case proceedings. Because an after-tax cost of debt is used, the overall WACC will tend to be lower than a comparable WACC calculated in a utility rate case proceeding. Another factor that may cause a difference is the fact that investment advisors will use a current cost of debt rather an embedded cost of debt. Consequently, it is difficult to back into any of the investment advisors' estimated costs of common equity even when they provide the overall WACC, i.e. discount rate, used to discount cash flows.

Although most of the advisors did not provide their estimated cost of common equity for Aquila's Missouri regulated operations and Great Plains Energy, a couple of them did. On page 91 of the prospectus, Blackstone provided an estimated cost of common equity of 9.5 percent when estimating GPE's implied offer price to Aquila's shareholders. Evercore provided an estimated cost of common equity for Great Plains Energy of 9.0 to 10.0 percent when estimating an implied price per share range. There are also costs of equity provided in estimating Aquila's cost of equity as a continuing stand-alone entity, but these are not good tests of reasonableness since they capture the risk Aquila had because of its failed non-regulated investments. These costs of equity were estimated at anywhere from 10.14 percent to 14.0 percent.

It could be argued that the investment advisors may estimate higher costs of common equity because of the recent decline in the stock market, but Staff does not believe it would be much higher because, while risk premiums have gone up, the risk-free rates have come down. Additionally, investment-grade utility companies' cost of debt has returned to more normal levels in the past month. Regardless, Staff believes this supports its recommendations in the nine percent range during the same period in which Blackstone did its analysis. It certainly illustrates the unreasonableness of GMO witness Hadaway's recommended ROE's which have been above 11 percent in cases during this same period.

The publicly-available information in the SEC filing also discussed perpetual growth rates used to arrive at certain stock price estimates. This information is directly relevant to this case since these can be used to test the reasonableness of the witnesses' perpetual growth recommendations in this case. Blackstone estimated an implied perpetual growth rate of 3.4 to 4.8 percent for Aquila's (GMO's) cash flows after 2013. Blackstone estimated an implied perpetual growth rate of 1.7 percent to 3.2 percent if Strategic Energy was excluded and 1.7 percent to 3.4 percent 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.

Although Staff has already provided its explanation as to why a quarterly-compounding adjustment is not needed in estimating the cost of capital, Staff also believes it is important to inform the Commission that based on the information provided in the prospectus, it does not appear that any of the financial advisors used quarterly cash flows to determine a "fair value" estimate for the acquisition of Aquila's Missouri electric utility properties.

Although Staff recommends that the Commission rely primarily on Staff's cost-of-common-equity recommendation using the multi-stage DCF analysis in this case when authorizing a fair rate of return, Staff recognizes that the Commission has expressed a preference in past cases to at least consider the average authorized returns as published by the Regulatory Research Associates (RRA).

According to RRA, the average authorized ROE for electric utility companies for 2008 was 10.46 percent based on 37 decisions (first quarter – 10.45 percent based on ten decisions; second quarter – 10.57 percent based on eight decisions; third quarter – 10.47 percent based on eleven decisions; and fourth quarter – 10.33 percent based on eight decisions).

The average authorized ROE for electric utility companies for 2007 was 10.36 percent based on 39 decisions (first quarter – 10.27 percent based on eight decisions; second quarter – 10.27 percent based on eleven decisions; third quarter – 10.02 percent based on four decisions; fourth quarter – 10.56 percent based on sixteen decisions).

Although average authorized ROEs tend to garner the most attention in rate cases, it is also important to consider average authorized rates of return (ROR) to provide some context for average authorized ROEs. Some companies' costs of debt may cause their ultimate authorized return to be somewhat higher than the average. Although the cost of debt is only adjusted in extraordinary circumstances (for instance in Aquila Inc.'s recent rate cases, the cost of debt had been adjusted to make it consistent with investment grade costs), there may be concerns about the reasonableness of these costs. Because it is the overall ROR (not the quoted average authorized ROE) that is applied to rate base to determine the revenue requirement, it would appear that this average would also be important in testing the reasonableness of the total cost of capital.

The average authorized ROR for electric utilities for 2008 was 8.25 percent based on 35 decisions (first quarter – 8.36 percent based on nine decisions; second quarter – 8.21 percent based on seven decisions; third quarter – 8.32 percent based on ten decisions; fourth quarter – 8.09 percent based on nine decisions).

The average authorized ROR for electric utilities in 2007 was 8.22 percent based on 38 decisions (first quarter – 8.44 percent based on eight decisions; second quarter – 7.94 percent based on eleven decision; third quarter – 7.90 percent based on four decisions; fourth quarter – 8.38 percent based on fifteen decisions).

It is important to note that Staff has not researched the specifics of most, if not all, of the cases cited in the RRA reports.

H. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 8.03 to 8.54 percent was developed for GMO's Missouri electric utility operations (see Schedule 21). This rate was calculated by applying an embedded cost of long-term debt of 6.75 percent and a cost of common equity range of 9.25 percent to 10.25 percent to a capital structure consisting of 51.03 percent common equity and 48.97 percent long-term debt. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that GMO's electric utility operations be allowed to earn a return on its rate base in the range of 8.03 percent to 8.54 percent.

Through Staff's analysis, it believes that it has developed a fair and reasonable return, which, when applied to GMO's jurisdictional rate base, will allow GMO the opportunity to earn the revenue requirement developed in this rate case.

Staff Expert: David Murray

V. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff is recommending the plant in service (plant) and accumulated depreciation reserve (reserve) balances based on the actual booked amounts as of the update period, September 30, 2008. This includes plant additions that have occurred since the test year ending December 31, 2007, and the related depreciation reserve balances. At the time of the true-up, adjustments to the plant will be updated to include plant additions placed in service during the period of September 30, 2008 through March 31, 2009, and the depreciation reserve balances related to those additions. These additions must be providing service to the customers before the plant is reflected in rates. During the analysis of the Company's plant reserve balances, Staff found GMO-Steam had made adjustments to the reserve account balances for retirement work in progress (RWIP). RWIP is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage. The retired plant and related depreciation reserve was removed from the Company's plant and reserve account balances as of the retirement date, but the related reserve for cost of removal and salvage remained as of September 30, 2008. Thus, the reserve was overstated for this retired plant, which necessitated an adjustment to remove the no longer in service plant from the reserve balances. Staff included a line item in the Accumulated Depreciation Schedule identifying the RWIP associated with Production, Transmission, Distribution, and General Plant.

Staff Expert: Karen Herrington

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

Cash Working Capital Schedule 8 identifies the amount of cash working capital that has been determined using a 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 were 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.

Prior to the KCP&L's acquisition of Aquila Inc which included GMO-Steam, the Company experienced financial difficulties resulting in third party lenders terminating their account receivables contracts. As a result, rate payers did not receive the benefits for selling the accounts receivable. This will be discussed in greater detail infra *Accounts Receivables Bank Fees*.

GMO-steam performed a lead-lag study using a method very similar to that used by Staff in previous cases. Staff did not perform a complete, independent CWC analysis in this case, instead relying on the calculations made by the GMO entities and Staff in previous cases. However, Staff identified a problem with the KCPL Gross Receipt Tax calculation and determined that it was appropriate to more closely analyze that calculation in the lead-lag study of the GMO entities.

GMO-Steam pays Gross Receipt Taxes (commonly referred to as franchise taxes) for the right to do business in the municipalities where they operate. 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 municipalities change their rates.

Staff reviewed the city ordinances for the Gross Receipt Tax (GRT) to obtain a better understanding of how the tax was imposed and how it was collected. Staff found the tax was based on previous revenues on a semi-annual, quarterly, or a monthly basis. Staff has determined that all municipalities served by the GMO entities require that the GRT be remitted to those taxing authorities after the GRT amounts are assessed, billed to GMO-Steam customers and collected by the Company. Since the Company remits the GRT to the taxing authorities after it collects it from its electric customers, these taxes are paid in the arrears. The Company bills for the collection of the GRT along with the billing of steam service and collects from the customers the same time it collects for the provision of service. Customers are providing the cash for the GRT in advance of when the GRT is paid to the taxing authorities which allows the Company to have use of these funds for a significant period of time prior to making payment to the municipalities. As a result of the analysis, Staff determined the GMO entities use the same methodology as Staff and treat the revenues as paid in the arrears. The calculations for the gross receipts taxes are reflected in the CWC schedule (Schedule 8) as line 18.

Staff Expert: Karen Herrington

C. Prepayments

Prepayments are investments a utility makes in assets prior to their use in providing utility service and are reflected in rate base. Staff included amounts for prepayments that L&P Steam require to provide electric utility service to their customers. Staff examined the steam prepayment account balances over the last several years on a month-by-month basis. Based on this review, and the variability in the monthly account balances, Staff determined the prepayment levels to include in the L&P Steam rate base by calculating an average of the end of month balances for the 13-months ending September 30, 2008. Staff used this approach because there was no discernable upward or downward trend in the monthly balances. Also, included in this monthly prepayment average is a balance for the ECORP common plant account that was allocated to MPS and L&P Electric and L&P Steam, accordingly. ECORP is a cost center that collects the common assets and expenses of the company between MPS, L&P Electric and Steam. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

D. Fuel Inventories

1. Coal Inventory

The Staff included in the rate base of GMO Steam an amount for coal inventory based on results obtained from the Staff's production cost model (fuel model). Among other things, the Staff uses its fuel model to determine an appropriate mix of generation unit and purchased power utilization to match the normalized native load of a utility. In doing so, the Staff also obtains 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 GMO, the Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. The Staff then multiplied this average daily burn by an appropriate number of days of coal inventory for each generation unit to arrive at the coal inventory amount shown as coal inventory in Rate Base Schedule 2.

2. Oil Inventory

The Staff used a 13-month average to determine the inventory level for oil consistent with how GMO determined its inventory level for oil in this case.

A 13-month average inventory reflects a utility's actual experience for the entire 12-month 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 would reflect 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 a utility'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. Accounting Schedule 2 - Rate Base reflects the Staff's inventory levels for coal and oil.

Staff Expert: V. William Harris

E. Materials and Supplies

Materials and supplies (M&S) represents investments in inventory for items such as spare parts, electric cables and poles, meters, and other miscellaneous items used in daily operations and maintenance activities by L&P Steam to maintain their production facilities and electric system. For L&P Staff decided that because of the decreasing balances in Account 154, the September 30, 2008 ending monthly balance was the most accurate way to measure the ongoing investment level in this asset. For account 163, there was a constant fluctuation in the months reviewed, so a 13-month average balance was used.

(Accounting Schedule 2)

Staff Expert: Bret G. Prenger

F. FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset

Financial Accounting Standard (FAS) 87 is the accrual accounting method for calculating pension cost for financial reporting purposes. However, for L&P steam, a rate case has not been filed since the 2005 rate case, Case No. HR-2005-0450. In that rate case most if not all of the administration and general (A&G) expenses, which include pensions and OPEBs, were allocated from L&P electric to L&P steam. Therefore, in this case the Staff recommends continuing to allocate a portion of the pension expense of L&P electric to L&P steam. During Case No. ER-2004-0034 and continued in Case No. ER-2005-0436 and Case No. ER-2007-0004, the Staff, MPS, L&P and all parties to these cases joined in or did not oppose a settlement agreement to resolve all differences involving pensions and OPEBS. The settlement agreements provide for the use of the minimum contributions required under the Employee Retirement Income Security Act (ERISA) for determining L&P electric pension cost for ratemaking purposes. ERISA was established by federal statute in 1976 and is intended to ensure the funding of defined benefit pension plans in the United States. The Company and the Staff have included an allocated portion of the L&P electric pension costs in the L&P steam cost of service that was included in the settlement agreements.

FAS 87 is an accrual accounting method required by the accounting profession under Generally Accepted Accounting Procedures (GAAP) for financial reporting purposes. Under FAS 87 a company accrues (expenses) an employee's earned pension benefits over the service life of the employee. The total obligation to the employee for pension benefits is accumulated annually until retirement in the Accumulated Benefit Obligation (ABO). Both financial statement expense recognition under FAS 87 and the funding requirements under ERISA are based upon the same pension plan obligation to employees enrolled in the plan. While different assumptions are used for the timing of pension cost recognition during the service life of the employee under FAS 87 and ERISA, both FAS 87 and ERISA are intended to address the same total ABO by the employee's retirement date. The Staff has historically used both FAS 87 and the ERISA minimum contributions for determining pension cost for ratemaking purposes.

In MPS and L&P"s last general electric rate case, Case No. ER-2007-0004, the parties entered into a settlement agreement to use the provisions that was established in MPS and L&P's previous rate case, Case No. ER-2005-0436, which included the following provisions:

1) A Prepaid Pension Asset representing negative pension cost flowed through in rates in prior cases was agreed to in the stipulation and agreement in Case No. ER-2004-0034. This Prepaid Pension Asset is being amortized to cost of service over 5 1/2 years for the MPS division and 9.25 years for the L&P division starting with the effective date of rates established in Case No. ER-2004-0034, April 22, 2004. The unamortized balance is included in rate base for the MPS and L&P divisions. This treatment was continued in the stipulation and agreement in Case No. ER-2005-0436 and ER-2007-0004.

2) Annual pension cost reflected in cost of service is to be based upon MPS and L&P's ERISA minimum contributions requirements.

3) A tracking mechanism tracks the difference between the pension cost included in rates and MPS and L&P's actual pension fund contributions during the period that existing rates are in effect. The resulting regulatory asset (actual fund contributions exceed rate recovery) and/or regulatory liability (actual fund contributions are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

The rate base amounts and cost of service adjustments the Staff has reflected in this current case, Case No. HR-2009-0092, are based on continuation of the agreements reached in the stipulation and agreements in Case Nos. ER-2004-0034, ER-2005-0436 and ER-2007-0004.

The Staffs rate base includes a Missouri jurisdictional balance of $474,520 for the L&P steam prepaid pension asset unrecovered balance, as of September 30, 2008. This amount will be updated through March 31, 2009, in the true-up audit for this case. As of September 30, 2008, L&P steam has collected $3,786 more in rates than the actual contributions made to the pension fund. This regulatory liability is reflected as a reduction to L&P steam rate base and amortized as a reduction to pension cost over 5 years. Adjustment E-159.3, in Schedule 10, adjusts the 2007 test year pension cost for the L&P steam to reflect a normalized level of contributions to the pension fund. Adjustment E-159.2, in Schedule 10, adjusts L&P steam 2007 test year pension cost to reflect the correct amortization amount for the Prepaid Pension Asset included in the stipulation and agreement in Case No. ER-2007-0004.

Staff Expert: Paul R. Harrison

VI. Income Statement - Revenues

A. Rate Revenues

1. <u>The Development of Rate Revenue in this Case</u>

a. Hourly Loads and Growth in Customer Loads

Staff used the Company's hourly test year load data and estimated the missing data for the test year. Staff then calculated the difference between the test year load energy and the billed energy for the update period. Staff increased each customer's test year hourly load by the percentage of difference between the test year load energy and the billed energy for the update period, on a company specific basis. The updated test year data was provided to Staff witnesses Michael Ensrud, for special contract adjustment calculations, and David Elliott, for fuel calculations.

b. Rate Revenue

Staff consolidated the updated test year hourly information to monthly energy and load figures, and then calculated revenues for all customers, except AGP, using current rates. Staff then added the AGP information provided by Staff witness Michael Ensrud, to arrive at total adjusted test year revenue.

Staff Expert: Thomas A. Solt

2. AG Processing Inc. Growth and Special Contracts

Staff proposes three (3) adjustments relating to Ag Processing Inc. (AGP) for GMO - one (1) adjustment relates to customer usage growth, and two (2) adjustments relate to ** ______ ** special contracts between AGP and GMO. The composite result of these adjustments were provided to Staff witness Tom Solt, and resulted in an increase of updated test year revenues of ** ________ **.

Impact of Growth

Using Staff witness Thomas A. Solt's calculation of annualized usage of mmBTUs (million British Thermal Units) for AGP, Staff has calculated the revenues associated with that usage being priced-out using current tariff rates and individual meter readings. The adjustment for AGP's customer growth results in an increase to test year revenues of ** ________ **.

Imputation of Revenue Related to Special Contracts

Staff is imputing revenues to reflect foregone income stemming from ** ___ ** agreements between AGP and GMO, made when GMO was named Aquila. While the Commission has allowed GMO to provide net revenue reductions to a specific customer, AGP, through special contracts, both of the Commission-approved Stipulation and Agreements pertaining to those revenue reductions have included provisions that result in the residual customer base not being required to pay higher rates to compensate for that voluntary revenue shortfall (Order Approving Unanimous Stipulation and Agreement in Case No. ER-2004-0034, which was consolidated with Case No. HR-2004-0024, effective April 22, 2004; and Order Regarding Stipulation and Agreement in Case No. HR-2005-0450, effective March 6, 2006.).

The Unanimous Stipulation and Agreement approved by the Commission in consolidated Case Nos. ER-2004-0034 and HR-2004-0024 contained the "hold harmless" provision that follows:

> **AGP Special Contract**
>
> 4. Aquila agrees to grant industrial steam customer AGP a five (5) year special contract, with a one (1) year evergreen provision, which special contract will provide a discount from steam tariffs, on file and approved by the Commission, in an amount of $35,000 per month (not to exceed the total amount billed in that month) in each month based upon an agreed upon load factor and usage level. Aquila **agrees that for future ratemaking determinations**, **AGP will be treated as if it were paying the full tariff rate.** (Emphasis Added)

The Non-Unanimous Stipulation and Agreement approved by the Commission in Case No. HR-2005-0450 reiterated the "hold harmless" provision, as follows:

> **Steam Service Agreement**
>
> 12. The Aquila/AGP Steam Service Agreement dated April 22, 2004 will be amended for the purpose of extending the term of the contract and all provisions including the pricing provisions, to April 21, 2010. **The Aquila/AGP letter agreement dated March 22, 2004 will continue in effect. Aquila agrees that for future ratemaking determinations, AGP will be treated as if it were paying the full tariff rate.** (Emphasis Added)

<u>Adjustment for Monthly Bill Credits</u>

An April 22, 2004 agreement between GMO and AGP contains the following provision:

> ** ____
> ____
> ____
> ____
> ____
> ____
> ____
> ____
> ______________________ **

Staff's adjustment imputes an additional $420,000 worth of revenues associated with the bill credits received by AGP during the test year. ($35,000 @12 months = $420,000 annually.) This adjustment was also made by GMO, as Adj. R 50. This imputation is necessary to hold ratepayers harmless from the revenues forgone by GMO under the Monthly Bill Credits special contract.

****** [redacted] ******

A March 22, 2004 agreement between GMO and AGP contains the following provision:

> ** [redacted]

[redacted]

[redacted]

NP

____

______________________________ **

SUMMARY OF STAFF ADJUSTMENTS RELATING TO AGP

Staff has adjusted revenues relating to AGP to reflect growth in units, and an imputation of revenues related to special contracts that should be borne by the shareholders. The total value of these three adjustments (** ____ **) is an increase of ** ________ ** to test year revenues for AGP, and were provided to Staff witness Thomas A. Solt.

Staff Expert: Michael J. Ensrud

VII. Income Statement - Expenses

Fuel Expense

1. Fixed Costs

Fuel costs that do not vary directly with fuel burned were determined independent of Staff's fuel model. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as fuel adders. Fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in the 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. Fuel adders include rail car expense, fly ash removal, freeze suppression and non-labor fuel handling costs.

The Staff used the actual cost incurred in calendar year 2007 (test year) as the annualized level for all fuel adders in this direct filing.

Staff Expert: V. William Harris

2. Variable Costs

The Staff estimates the variable steam fuel expense for GMO for the updated test year ending September 30, 2008 to be $10,842,125.

The Staff used the RealTime ® production cost model to perform an hour-by-hour chronological simulation of GMO's generation and power purchases (electric model), and an hour-by-hour chronological simulation of Lake Road Plant steam boiler steam generation (steam model). The Staff used both electric and steam models to determine annual variable cost of boiler fuel consumption necessary to economically match GMO's steam sales load within the operating constraints of it's resources used to meet that load. These amounts are supplied to Auditing Staff who use this input in the annualization of fuel expense.

Both models operate in a chronological fashion, matching each hour's energy demand before moving to the next hour. The electric model schedules generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operation constraints. This electric model closely simulates the way a utility should dispatch its generating units and purchase power to match the net system load in a least cost manner. The steam model schedules boilers to dispatch in a least cost manner based upon fuel cost while taking into account boiler operation constraints. This steam model closely simulates the way a utility should dispatch its boilers to match steam sales load in a least cost manner.

Inputs provided by the Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit/boiler planned and forced outages. The Staff relied on GMO responses to data requests for factors relating to each generating unit such as: capacity of the unit, unit heat rate curve, capacity of the boilers, boiler efficiencies, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Information from GMO's firm purchased power contracts such as hourly energy available and prices are also inputs to the model.

Staff Expert: David W. Elliott

The Staff computed the variable fuel costs for GMO Steam using prices and quantities incurred by GMO through September 30, 2008. This included using fuel prices for coal and oil, including transportation charges in fuel account 501 (coal) and 547 (natural gas and oil).

a. Coal Prices

The Staff determined its coal price by generation facility based on a review and analysis of GMO's coal purchase (supply) and coal transportation (freight) contracts. The Staff's proposed coal prices reflect GMO's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect at September 30, 2008.

Staff Expert: V. William Harris

b. Natural Gas Prices

The natural gas prices used as an input to the Staff's fuel model were calculated using the actual delivered cost of natural gas for the 2007 test year.

Staff Expert: V. William Harris

c. Oil Prices

The Staff used the actual cost GMO paid for its most recent fuel oil purchases. GMO burns 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 GMO does not make purchases during the majority of the year. Thus, any trend in costs could be misleading because of the limited amount of available data. The Staff believes GMO's most recent fuel oil purchase prices are the best available fuel oil cost to input into the fuel model for determining GMO's variable fuel expense on a going forward basis.

Staff Expert: V. William Harris

3. Capacity Contract Prices and Energy

Capacity contracts are contracts for a specific amount of capacity (megawatts) and a maximum amount of hourly energy (megawatthours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. Capacity contracts include: Gray County Wind Contract, NPPD Cooper Contract, NPPD Gentleman Contract, and a generic contract.

GMO's actual hourly contract transaction prices in the period of twelve months ending September 30, 2008, obtained from the data GMO supplied to comply with 4 CSR 240-3.190 were used to calculate the average monthly prices.

Staff Expert: David W. Elliott

4. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the MPS and L&P generating unit outages were normalized by averaging the nine years of actual values taken from data supplied by GMO. In order to capture this variability, outages for the Lake Road boilers located in L&P service area in St Joseph, Misouri, were normalized by averaging the seven years of actual values taken from data supplied by GMO.

Staff Expert: David W. Elliott

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

1. Payroll Costs

Upon the consummation of the acquisition of the former Aquila regulated Missouri utilities, (MPS, L&P electric and L&P Steam) approved by the Commission in Case No. EM-2007-0374, remaining employees of the former MPS and L&P divisions became employees of KCPL. The transfer of the former Aquila employees was made at the close of the acquisition transaction July 14, 2008. The former Aquila entities now are providing utility services under the name Greater Missouri Operations: 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 KCPL service territory and the two GMO entities, MPS and L&P. Since L&P operations supplies utility services to electric and steam customers, L&P labor costs must be further allocated between the electric and steam operations. This is accomplished through jurisdictional allocations in Staff's accounting schedules. Developing an accurate cost allocation methodology was critical in assuring that proper labor costs were being correctly assigned appropriately to the three separate operating entities, KCPL, GMO MPS and GMO L&P.

In its September 30, 2008 updated filing, the Company assigned costs based upon annualized levels in its original filing. Staff examined these calculations and compared them with test year labor amounts for KCPL, MPS and L&P. Staff also reviewed the estimated allocation factors developed by KCPL in the aforementioned acquisition case. In addition, Staff examined actual payroll costs charged to KCPL, MPS and L&P from the inception of the acquisition (July 14, 2008) through November, 2008. The actual charges made to the post acquisition KCPL and GMO operations formed the basis of the allocation percentages used as a method to allocate base payroll costs to the respective KCPL, MPS and L&P entities.

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. 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 Nuclear Operating Corporation, 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 September 30, 2008. Wages and salaries as of September 30, 2008 were applied to each individual employee to compute the total GPE and KCPL payroll costs on an annual basis.

As of September 30, 2008, GMO's holding company, GPE, has 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.

Through discussions with the Company, it was determined that 71 employees were part of the acquisition transition work force and should be removed from the list of regular employees. Also removed were non-active employees on various types of extended leave. Temporary and intern employees were annualized based upon a three-year average of such employees. One GPE corporate employee who is a lobbyist for the corporation was not included in Staff's annualized payroll. The GPE employees were segregated for their allocation to regulated operations based on the allocation for 2007 of 69.03%. The amount of

GPE annualized payroll as well as a three-year average of GPE overtime was allocated to KCPL and GMO MPS and GMO L&P.

On December 16, 2008, GPE was restructured with all GPE and GPES employees moving to the KCPL organization becoming KCPL employees. Since this occurred outside the update period used in this case of September 30, 2008, Staff has not determined the allocation process to be used for the true-up. There will be no GPE employees to allocate in the future and Staff will have to examine the impacts of the GPE restructuring on the regulated operations of the Company.

Overtime payroll for L&P was calculated based upon a three-year average of overtime costs unique to the division. The amount is specific to L&P service territory 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 L&P.

As the result of KCPL's operating agreements on 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, MPS and L&P payroll costs. The level of payroll billed by KCPL to its joint owners in the Iatan and LaCygne generating stations was also based upon a three-year average. 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 Empire District Electric Company, the other partner in Iatan, and to Energy Company, the 50% partner in the two LaCygne generating facilities.

The total annualized GPE and KCPL payroll costs allocated to the L&P Steam service territory also must 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 the company. The construction amounts are assigned to the work orders for construction projects. The amounts that are included in the revenue requirement calculations for L&P Steam are the levels assigned to payroll expenses through the O&M expense ratios.

After allocation between expense and construction based on the test year expense factor, the adjustment for payroll was distributed by individual FERC account based upon the actual distribution for each of those accounts for 12-months ending December 31, 2007, the test year used in this case. Staff's accounting schedules reflect approximately seventy (70) adjustments for L&P Steam by FERC account to reflect the adjustments required to restate the 2007 test year payroll to an annualized level as of September 30, 2008. These adjustments are further allocated using the jurisdictional allocators in Staff's accounting schedules

The following adjustments to the income statement reflect annualized payroll for GMO L&P Steam as of September 30, 2008: E-4.1, 11.1, 16.1, 17.1, 22.1, 23.1, 24.1, 25.1, 26.1, 35.1, 40.1, ,41.1, 46.1, 47.1, 48.1, 63.1, 64.1, 69.1, 71.1, 72.1, 73.1, 75.1, 76.1, 77.1, 78.1, 79.1, 80.1, 85.1, 89.1, 90.1, 92.1, 93.1, 95.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 107.1, 108.1, 109.1, 110.1, 111.1, 115.1, 116.1, 117.1, 118.1, 119.1, 120.1, 121.1, 122.1, 124.1, 128.1, 129.1, 130.1, 131.1, 132.1, 133.1, 134.1, 136.1, 139.1, 142.1, 145.1, 146.1, 152.1, 166.1, and 169.1

Staff Expert: Keith A. Majors

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 and interns, an aggregate tax rate was applied based on the annualized payroll taxes for base payroll. The payroll taxes follow the same allocation process used to allocate base payroll.

Adjustment E-186.2 to the Income Statement reflects the annualized payroll taxes for GMO L&P Steam.

Staff Expert: Keith A. Majors

3. Payroll Related Benefits

Staff annualized 401k expense based upon the test year percentage KCP&L match to eligible earnings applied to the L&P share of total annualized payroll, reduced for the payroll expense factor to capital. Staff used the test year KCP&L match to earnings as all employees are now KCPL employees and the aggregate Company match to earnings is the most appropriate for the cost of service.

Medical costs were annualized based upon a calculation of twelve months ending September 30, 2008 L&P self funded cost, net of the test year ratio of employee contributions and including a small portion of premium based coverage.

By the true-up date of this case, all former Aquila employees will receive medical coverage through the Voluntary Employee Benefit Association (VEBA). Staff will examine the change in these costs and adjust them to an annualized level at the true-up.

Adjustments E-159.1 and 159.10 to the Income Statement reflect annualized employee benefits for GMO L&P Steam.

Staff Expert: Keith A. Majors

4. True-up of Payroll Costs

Staff will update the total payroll costs for the true-up in this case which is based on March 31, 2009. The same methodology used to annualize payroll as of September 30, 2008, will be used for the March 31, 2009 true-up.

Staff Expert: Keith A. Majors

5. FAS 87 and FAS 88 Pension Costs

Financial Accounting Standard (FAS) 87 is the accrual accounting method for calculating pension cost for financial reporting purposes. However, for Kansas City Power & Light Greater Missouri Operation's or the former Aquila Networks Missouri Public Service and St. Joseph Light and Power regulated entities, MPS and L&P, both the Staff and the Company recommend continuation of the settlement agreement originally reached in Case No. ER-2004-0034 and continued in Case No. ER-2005-0436 and Case No. ER-2007-0004. The settlement agreement provides for the use of the minimum contributions required under the Employee Retirement Income Security Act (ERISA) for determining MPS's and L&P's pension cost for ratemaking purposes. ERISA was established by federal statute in 1976 and is intended to ensure the funding of defined benefit pension plans in the United States.

FAS 87 is an accrual accounting method required by the accounting profession under Generally Accepted Accounting Procedures (GAAP) for financial reporting purposes. Under FAS 87 a company accrues (expenses) an employee's earned pension benefits over the service life of the employee. The total obligation to the employee for pension benefits is accumulated annually until retirement in the Accumulated Benefit Obligation (ABO). Both financial statement expense recognition under FAS 87 and the funding requirements under ERISA are based upon the same pension plan obligation to employees enrolled in the plan.

While different assumptions are used for the timing of pension cost recognition during the service life of the employee under FAS 87 and ERISA, both FAS 87 and ERISA are intended to address the same total ABO by the employee's retirement date. The Staff has historically used both FAS 87 and the ERISA minimum contributions for determining pension cost for ratemaking purposes.

In MPS's and L&P's last general electric rate case, Case No. ER-2007-0004, the parties entered into a settlement agreement to use the provisions that were established in MPS's and L&P's previous rate case, Case No. ER-2005-0436, which included the following provisions:

1) A Prepaid Pension Asset representing negative pension cost flowed through in rates in prior cases was agreed to in the stipulation and agreement in Case No. ER-2004-0034. This Prepaid Pension Asset is being amortized to cost of service over 5 1/2 years for the MPS division and 9.25 years for the L&P division starting with the effective date of rates established in Case No. ER-2004-0034, April 22, 2004. The unamortized balance is included in rate base for the MPS and L&P divisions. This treatment was continued in the stipulation and agreement in Case No. ER-2005-0436 and ER-2007-0004.

2) Annual pension cost reflected in cost of service is to be based upon MPS and L&P's ERISA minimum contributions requirements.

3) A tracking mechanism tracks the difference between the pension cost included in rates and MPS and L&P's actual pension fund contributions during the period that existing rates are in effect. The resulting regulatory asset (actual fund contributions exceed rate recovery) and/or regulatory liability (actual fund contributions are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

The rate base amounts and cost of service adjustments the Staff has reflected in this current case, Case No. ER-2009-0090, are based on continuation of the agreements reached in the stipulation and agreements in Case Nos. ER-2004-0034, ER-2005-0436 and ER-2007-0004.

The Staffs rate base includes a Missouri jurisdictional balance of $2,233,545 and $16,121,101 for the MPS and L&P divisions prepaid pension asset unrecovered balance, respectively, as of September 30, 2008. This amount will be updated through March 31, 2009, in the true-up audit for this case. As of September 30, 2008, MPS and L&P divisions have collected $4,344,194 and $8,748, respectively, more in rates than the actual contributions made to the pension fund. This regulatory liability is reflected as a reduction to MPS's and L&P's rate base and amortized as a reduction to pension cost over 5 years. Adjustments E-156.7 and E-159.4, in Schedule 10, adjust the 2007 test year pension cost for the MPS and L&P divisions, respectively, to reflect a normalized level of contributions to the pension fund. Adjustments E-156.6 and E-159.3, in Schedule 10, adjust MPS's and L&P's 2007 test year pension cost to reflect the correct amortization amount for the Prepaid Pension Asset included in the stipulation and agreement in Case No. ER-2007-0004.

Staff Expert: Paul R. Harrison

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

Other Post-Employment Benefit Costs are those costs incurred by the Company to provide certain benefits to retirees such as medical and life insurance benefits. The Company must determine its OPEBs expenses based on Financial Accounting Standard No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions (*FAS 106) and Staff has provided sufficient costs in its revenue requirement calculation to reflect a proper level for these post-employment benefit costs for L&P steam. Section 386.315, RSMo. 2000, requires that the Missouri Public Service 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 Accounting Standard 106 expenses typically include retiree medical, dental, vision and life insurance benefit costs.

Section 386.315, RSMo requires a utility to use an independent external funding mechanism that limits restricts disbursements only for qualified retiree benefits" for the FAS 106 costs recognized in a utility's financial statements and that all the funds be used for employee or retiree benefits.

The L&P steam is funding its annual FAS 106 costs. Staff adjustments E-159.4 adjusts the L&P steam test year 2007 FAS 106 OPEB costs to reflect the more current FAS 106 calculation as of September 2008.

The Staff's adjustment annualizes OPEBs expense as calculated under FAS 106 for L&P steam employees. OPEB expense reflects L&P steam's current liability to provide retiree medical payments to its current employees as well as to its retired employees.

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 FAS 106. FAS 158 requires recognition of the overfunded or underfunded status of pension and other postretirement benefit plan 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, 2008, the measurement date is required to be the employers' fiscal year end.

Additionally, through meetings with the Company, the Staff discovered that the Company made a determination to combine all of its pensions and OPEBs into one plan. Through these meeting and data request responses from the Company, it is the Staff's understanding that KCPL, MPS, L&P and L&P steam expect significant increases in their pension and OPEBs costs on or about the time of the true-up of this rate case. The Staff has submitted data requests to obtain additional information and has requested copies of the Company's combined actuary reports as soon as they are available. These issues will be addressed in the true-up phase of this rate case.

Staff Expert: Paul R. Harrison

7. Supplemental Executive Retirement Plan (SERP) Expense

Included in the Staff's revenue requirement recommendation is the test-year amount of recurring SERP payments made by the Company to its former executive employees. A SERP is an additional executive pension compensation program which provides benefits to highly-compensated employees over and above the benefits provided under the regular pension plan. In the test year MPS made $39,751 in SERP payments. In Adjustment E-156 the Staff removed the test year per book amount of SERP expense and included MPS' 2007 actual SERP payments.

The Staff has not included in the Company's revenue requirement any SERP payments for L&P. When Aquila purchased L&P in 2000, it also purchased the assets in L&P's funded SERP. It has been the Staff's position in prior rate cases and continues to be in this case that these assets are sufficient to pay for a reasonable level of SERP expense over the lifetime of the former St. Joseph Light and Power (SJLP) executives. Therefore, since Aquila purchased the assets in the SERP fund when it purchased L&P, there is no longer any SERP expense for the former SJLP executives.

Because of SERP's unique nature and the fact that the benefit represents an additional executive pension benefit over and above what is already provided in the regular pension plan, the Staff treats SERP costs somewhat differently from normal employee pension costs. The Staff's policy has been and continues to be the recommendation that SERP costs be included in the Company's cost of service if such costs are not significant, are reasonably provided for, and are able to be quantified under the known and measurable standard. MPS' annual recurring SERP payments of $39,751 meets this test.

Staff Expert: Charles R. Hyneman

8. Short Term Annual Incentive Compensation

The Aquila Variable Compensation was designed to grant cash awards based upon metrics in corporate, state, and individual employee measures. Within these measures are various metrics determined by management with various weights. The level of achievement of these goals, from threshold to maximum, determines the amount of weighting of that goal. Target award amounts are based upon classification of employee by band and status, field or support. Staff has examined goals and metrics of this program in prior cases and has found them to be prudent with the exception of metrics based upon financial measures.

The former Aquila entities also employed a profit sharing program which awarded additional funds to employee 401k contributions.

However, upon the acquisition of Aquila, these programs were discontinued and will not pay any awards after the 2007 plan year. All obligations to former Aquila employees were satisfied prior to the merger. The Company did not attempt to normalize these costs. Therefore, Staff is removing the test year short term incentive compensation charged to MPS and L&P.

All KCP&L employees, including all former Aquila employees now employed by KCP&L, are covered under KCP&L's three short term incentive compensation programs. In Case No. ER-2009-0089, Staff removed the cost of the test year short term incentive compensation from the cost of service. Because of this removal, there is no allocation of short term incentive compensation from KCP&L to MPS or L&P similar to the allocation of payroll costs.

Adjustments E-159.7 and 159.8 to the Income Statement reflect the adjustments to remove short term incentive compensation from the cost of service for GMO L&P Steam.

Staff Expert: Keith A. Majors

9. Long Term Incentive Compensation

During the test year, restricted stock was granted to senior executives of Aquila.

Restricted stock is stock which must be held for a specific period of time before is can be transferred or sold.

Staff is recommending the test year cost of equity compensation be excluded from the cost of service on the following rationale:

1) Equity compensation was awarded based upon goals which are entirely or primarily tied to earnings, beneficial to shareholders, not customers.
2) Unlike other forms of employee compensation, equity compensation does not require a cash outlay by GMO MPS and L&P.
3) The program that granted these stock awards is no longer active and no additional grants will occur. All obligations to former Aquila employees under this plan have been satisfied.

Adjustment E-159.9 to the Income Statement reflects the adjustment to remove restricted stock expense from the cost of service of GMO L&P Steam.

Staff Expert: Keith A. Majors

C. Maintenance Normalization Adjustments

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

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

Staff analyzed maintenance costs from 2001 through 2008 by functional area for production, transmission, distribution, and by FERC account for GMO-MPS and GMO-L&P. Staff separated maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff annualized payroll, reflecting the price increases for labor that generally occurs each year. A detailed staff position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report.

Several steps were taken to analyze the maintenance data. Those included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by Staff, was to compare functional averages which included using a 2-year average through a 7-year average to determine if there were fluctuations with each functional area. These steps were also compared to the 2007 Test Year. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs. Based on data provided by the Company, initiatives implemented by the Company to reduce maintenance costs, and a Commission rule related to preventative maintenance with Transmission and Distribution, Staff chose to use the 2007 test year for distribution and GMO-L&P reflect an upward trend therefore; Staff calculated an average of the 2007 and 2008 balances to account for the increased costs. The costs were then allocated to GMO-Steam. Adjustments: E-22.2, 23.2, 24.2, 25.2, 26.2

Staff Expert: Karen Herrington

D. Other Non-Labor Adjustments

1. Employee Relocation Expense

The Staff submitted Data Request No. 284 asking the Company to "provide former Aquila entities, (MPS, L&P and L&P Steam) employee relocation expense charged to general ledger for the most current 5 years as of December 31, 2007, updated through September 30, 2008". The Company responded that "Aquila recorded employee expense in account 926000 with resource code 1724" and they listed the employee relocation expense for MPS and L&P through the merger date, July 14, 2008. The Staff noticed that L&P employee relocation expense had a credit balance of ($40,934) for the 2007 test year. This appears to be a reversal entry from the prior year. The Staff removed the credit balance from L&P's 2007 test year amount and did not make an adjustment for MPS 2007 test year amount for employee relocation expense. (Staff adjustment E-153.4 adjusts L&P 2007 test year employee relocation expense.)

Staff Expert: Paul R. Harrison

2. Lease Expenses

Lease costs are those costs incurred by MPS and L&P for the leasing of its corporate headquarters, equipment and storage units. Staff examined these costs and found that in 2008, lease payments were reduced and made an adjustment to reflect these lower costs in rates.

The Staff submitted Data Request No. 16 asking MPS and L&P to provide a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri utility operations.

The Company's response to this data request indicates that MPS's and L&P's 2007 cost of service included annual lease expense of $1,443,199 and $410,615 for MPS and L&P, respectively. The data for 2008 for the response to this same data request indicates that the annualized 2008 lease expense is $1,010,178 and $334,844 for MPS and L&P, respectively. The Staff used the annualized MPS and L&P lease expense provided in the response to this data request to adjust MPS and L&P lease expense. This annualization resulted in a decrease in the level of MPS and L&P lease expense of $433,022 and $75,771 respectively. (Staff adjustments E-163.1 and E-168.1 adjust MPS and L&P test year 2007 lease expenses)

Staff Expert: Paul R. Harrison

3. Property Tax Expense

Every year, KCP&L-Greater Missouri Operations (GMO) receives a property tax bill from each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property GMO owns on the first day of that calendar year. The property taxes assessed on January 1 of each year are typically not due to the taxing authorities until December 31 of that year and in the state of Kansas, part of the year's property taxes are not due until late in the first quarter of the following year. The test year being used in this case is the 12-month period ending December 31, 2007, updated through September, 2008. Since the update period in this case is September 30, 2008, Staff has determined the annualized property taxes based on the property in the GMO-Steam territories that was in-service on January 1, 2008. Staff applied a property tax ratio based on actual 2007 property tax payments to January 1, 2007 plant. This ratio of property taxes when applied to the January 1, 2008 plant balance provides the amount of property taxes expected to be paid for 2008. Since the actual 2008 property taxes owned by the Company have been paid as of December 31, 2008, Staff plans on updating its property taxes for the true-up which will be through March 31, 2009.

Because the update in this case is September 30, 2008 property tax expenses were annualized as of the January 1, 2008 date. This calculation is an estimate for the total 2008 property tax expense. Both Staff and the Company have typically accomplished this by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year. For the current rate case, Staff has obtained from GMO-Steam the total amount of taxable property owned on January 1, 2008, and then applied to it the tax rate assessed to the Company in 2007. Staff believes that the property tax expense arrived in this manner is the best available information, since it relies on the actual January 1, 2008 balance of GMO-Steam property, and uses the most recent, known tax rate (2007), without attempting to estimate any change in the rate of taxation for 2008 that is not known as of the update period September 30, 2008. Even though the 2008 property tax payments are known at the end of the year and at the time of this filing, since there is a true-up scheduled in this case, Staff felt it was appropriate to include the annualized property taxes through the update period, September 30, 2008. The property taxes will be trued-up during that phase of the case.

Staff adjusted test year property tax expense in order to include in rates the annualized level of 2008 property taxes. Staff's approach is consistent with that taken previously and has received several favorable rulings from the Commission in prior cases, most recently in KCPL's 2006 rate case. In its Report and Order issued in Case No. ER-2006-0314 the Commission stated the following:

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

Based on the methodology addressed earlier, Staff issued an adjustment to include an annualized amount for property taxes. Adjustment for GMO-Steam E-186.

Staff Expert: Karen Herrington

4. Advertising Expense

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

1. General: advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the company's public image;
5. Political: advertising associated with political issues.

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

Based on discussions and GMO responses to Staff data requests, the Staff has included for L&P Steam the level it believes will be a continuing annual amount of advertising expense that will be necessary for the provision of utility service.

Staff Expert: Bret G. Prenger

5. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that L&P Steam charged to its utility accounts during the test year. The Staff accepted Company adjustments CS-60 for L&P which removed the test year level of dues and donations recorded above the line.

Staff Expert: Bret G. Prenger

6. Account Receivable Bank Fees

The selling of accounts receivable results in the Company collecting revenues on an accelerated basis from the lending institution. The adjustment for bank fees relate to the costs of this program. The benefit to the Company is that it receives enhancement to its cash management. For rate making purposes this enhancement is reflected in the acceleration of the collection process, identified through a shorter revenue lag in the CWC schedule, than otherwise would have occurred absent the sale of the accounts receivables. As mentioned earlier, the GMO entities were unable to continue an accounts receivable sale program due to poor financial decisions. Prior to its financial downturn, the Company had established a program with Ciesco, an affiliate of Citibank. The program involved a loan from a third party backed by the GMO entities accounts receivables. When the Company began to experience a severe decline in its credit rating, Ciesco terminated the program.

The termination of the accounts receivable program was the direct result of the Company's poor financial condition and has caused a detriment to all the GMO entities. The loss of the sale of the accounts receivables resulted directly from the problems that Aquila faced in its non-regulated ventures. Based on the Company's past financial problems and the KCPL acquisition, Staff determined an adjustment should be made for the bank fees had the program been in place. KCPL currently sells approximately 57% of its account receivables, which include the account receivables of the GMO entities. When calculating an appropriate amount for the GMO entities, Staff used the same percentage based on the receivable balance from July 31, 2008 and December 31, 2008. GMO Steam received an allocated portion of the bank fees. Adjustment E-136.

Staff Expert: Karen Herrington

7. Miscellaneous Adjustments

There were several adjustments that were required to be made to certain of L&P steam 2007 income statement accounts to remove the effects of credits that were made to record expenses as regulatory assets, remove nonrecurring revenue and expenses, and for other reasons. Both KCPL and the Staff made these adjustments. These adjustments include:

E-128.2 – eliminate duplicate payment and GUI project settlement from test year expense from account 901
E-153.1 – eliminate non-labor expenses related to acquisition, transition and asset sales from account 921
E-159.5 - remove bonus paid related to acquisition, transition and asset sales from account 926
E-165.1 - remove duplicate payment made in January of 2007 to Burnet, Duckworth and Palmer from account 930
E-169.2 - eliminate lease payments for Raytown 750 building that was sold from account 935

Staff Expert: Paul R. Harrison

8. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses. Likewise, certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect. Insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates. The unamortized balance of the prepaid insurance will be addressed by Staff witness Keith Majors.

During the audit, Staff reviewed the Company's insurance policies for the following forms of insurance; General Liability, Fire, Storage Tank Liability, Worker's Compensation, and Property Insurance. The coverage period for the policies was April 2007 through April 2008. In addition, the Company provided insurance amounts for the coverage period beginning April 2008. However, the Company did not provide the supporting insurance policies for April 2008 through April 2009. Based on the information provided by the Company, an annualized insurance amount was calculated by using the insurance premiums for April 2007 through April 2008 which were provided in the insurance policies. The annualized amount was allocated between KCPL, GMO-MPS, GMO-LP and GMO-Steam.

Staff Expert: Karen Herrington

9. Injuries and Damages

Injuries and Damages relates to insurance for claims that are not covered by the Company's insurance policies. Injuries and Damages usually consist of claims associated with General Liability, Worker's Compensation, and Auto Liability. Staff analyzed three years of data and determined a three-year average including the period of 2005 through 2007, using the actual cash payments to normalize the Company's costs associated with Injuries and Damages. These actual cash payments are those paid to individuals who had injuries and claims against the Company. As a result of these injuries, L&P electric and L&P steam made cash settlements. A three-year average was used based on the data received from the Company. Adjustments E-158.1 reflects a normalized level of costs for injuries and damages for GMO Steam

Staff Expert: Karen Herrington

10. Rate Case Expense

Rate case expenses are costs incurred by a utility in preparing and prosecuting its filing for rate relief. In this case, the Company has incurred expenses in conjunction with legal counsel, regulatory consulting, and hired expert witnesses.

Staff utilized GMO records and responses to data requests to determine the appropriate level of rate case expense for inclusion in rates. Amounts from both Outside Services and Regulatory Expense accounts were taken into consideration as GMO determined they were incurred for the current rate case. Staff requested actual billings and invoices from the Company to examine the reasonableness of the costs incurred. Staff has included in this case actual amounts incurred through September 30, 2008 that were determined to be reasonable and relate to the preparation of L&P Steam's rate case filing.

As the GMO incurs additional rate case expense, Staff will include actual costs deemed to be reasonable and prudent to develop an amount of on-going rate case expense level which it will recommend be recovered in rates. The Staff is normalizing rate case expense over two years as proposed by GMO in this case.

Staff Expert: Bret G. Prenger

11. Public Service Assessment Fee

The Public Service Commission assessment (PSC Assessment) is an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs for regulating those utilities. The PSC Assessment is charged to regulated utilities operating in Missouri.

The PSC Assessment for L&P steam operations was annualized using the latest assessment available for the current fiscal year (FY-2009) on information obtained from the Commission's records. The annualized assessments were compared to the 2007 PSC Assessment amounts included in the test year to form the basis of Staff Adjustment E-163.2.

Expert: Bret G. Prenger

VIII. Depreciation Summary

The Staff conducted a depreciation study of the capital assets of the electric and industrial steam operations of KCP&L-Greater Missouri Operations Company (GMO), including an analysis of the accumulated reserve for depreciation. GMO has two operating divisions—the former Aquila Networks-MPS division (GMO-MPS) and the former Aquila Networks-L&P division (GMO-L&P). GMO-L&P has both electric and industrial steam operations. GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam each have separate, distinct, and independent Commission-ordered depreciation rates; therefore, the Staff analyzed depreciation rates for each in its depreciation study. Based on its study, the Staff recommends separate depreciation rates for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam which, when applied to the plant-in-service (on a Missouri Adjusted Jurisdictional basis) as of September 30, 2008, generated the depreciation expenses of GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam used in developing the Staff's revenue requirements for each—GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam. This was necessary since the customers of GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam each have rates based on distinct, independent, and separate tariffs which generate separate revenue requirements.

Staff's proposed depreciation rates for GMO-MPS would decrease the currently ordered annual depreciation expense from approximately $50.5 million to $45 million, a reduction of approximately $5.5 million.

Staff's proposed depreciation rates for GMO-L&P electric would decrease the currently ordered annual depreciation expense from approximately $11.5 million to $10.4 million, a reduction of approximately $1.1 million.

Staff's proposed depreciation rates for GMO-L&P industrial steam would decrease the currently ordered annual depreciation expense from approximately $0.7 million to $0.6 million, a reduction of approximately $0.1 million.

Schedules 3-1 and 3-2 are listings, by plant account, of the Staff's proposed depreciation rates for GMO-MPS and GMO-L&P electric in Case No. ER-2009-0090, and Schedule 3-3 is a listing, by plant account, of the Staff's proposed depreciation rates for GMO-L&P industrial steam in Case No. HR-2009-0092.

Schedules 4-1, 4-2 and 4-3 are listings, by plant account, of Staff's proposed depreciation parameters for each—GMO-MPS, GMO-L&P electric and GMO-L&P industrial steam in Case No. ER-2009-0090 and Case No. HR-2009-0092, respectively. Those schedules also include a comparison of Staff's recommended new depreciation rates to the current Commission-ordered rates (ordered in Case No. ER-2007-0004 effective May 27, 2007) for each division, respectively, which include the Company's corporate plant accounts and they offer a comparison to the depreciation rates for each division, respectively, that are developed in the Company's 2008 depreciation study, excluding the Company's corporate plant accounts. The Company failed to submit to Staff a depreciation study of its corporate plant accounts and a historical database of these plant accounts (Schedule 9-1), in accordance with 4 CSR 240-3.175(1)(B)2. The Company's corporate plant accounts, known as ECORP after Aquila Inc.'s acquisition by Great Plains Energy, will be discussed in more depth below.

Schedules 5-1, 5-2, and 5-3 are listings, by plant account (excluding the corporate plant accounts) as of December 31, 2007, of the accumulated reserve for depreciation and theoretical reserve amounts for each—GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Case No. ER-2009-0090 and Case No. HR-2009-0092, respectively.

Staff's study notes an over-accrual of the accumulated reserve for depreciation (excluding ECORP) of approximately $145.3 million, $72.5 million, and $0.3 million for each--GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively, for a Company total of over $218 million.

Staff's calculation of the ECORP accumulated reserve for depreciation, as of September 30, 2008, is shown in Schedule 2. Staff has adjusted the Company's ECORP reserve amounts (Schedules 8-1 and 8-2) to include approximately $4.2 million of depreciation accrual that would exist if the Company had continued use of its authorized depreciation rates on all accounts (Schedules 9-2 through 9-6), approximately $4 million of reserve deficiency created by the occurrence of premature retirements after the Company was acquired by Great Plains Energy (Schedules 10-1 through 10-3), and an assignment (on a weighted average per reserve account) equal to the reduction of the reserve overstatement that is currently assigned to GMO-MPS and GMO-L&P electric rather than the ECORP accumulated reserve for depreciation (Schedules 11-1 through 11-6 and 12-1 through 12-4). Currently, this reduction of the reserve overstatement is shown assigned to these two divisions as UCU Common General Plant.

Staff's total recommended adjustment to ECORP accumulated reserve for depreciation is approximately a $10.7 million reduction including the reduction of the reserve overstatement for GMO-MPS and GMO-L&P of $14,076,021 and $4,744,482, respectively, using a weighted average of each ECORP reserve account's balance as of September 30, 2008, an increase of the reserve for GMO-MPS and GMO-L&P of $2,966,218 and $976,648, respectively, and an increase of the reserve for GMO of $4,221,178. Staff's review of the Company's records through December 31, 2008 found additional reserve deficiencies, of approximately $1 million, from additional premature retirements, that cause three of the five ECORP accounts to have negative reserve amounts. ECORP accounts 390.00, Structures and Improvements, 391.00, Office Furniture, and 397.00, Communications Equipment, all have negative reserves at December 31, 2008. Only ECORP accounts 391.02, Computer Hardware and 391.04, Computer Software, have positive reserve balances. Staff will address these amounts in its true-up filing.

Staff recommends that a portion of the Company's $218 million over-accrual could be assigned in the future to ECORP to address the reserve reductions noted above.

Schedule 1 is the Company's 2008 depreciation study submitted to Staff in September 2008. As noted above, the Company's corporate accounts are not included in the Company's 2008 depreciation study.

A. Depreciation

Depreciation is the loss, not restored by current maintenance, which is due to all factors causing ultimate retirement of the property. These factors include wear and tear, decay, inadequacy, obsolescence, changes in the art, and requirements of public authorities.

The purpose of depreciation in a regulatory setting is to recover the cost of capital assets over the useful lives of the assets. The depreciation rate for each plant account is designed to recover, over the average service life of the assets in that account, the original cost of the assets plus an estimate for any cost of removal less scrap value. Annual depreciation expense for a plant account is the depreciation rate for that plant account multiplied by the balance of plant in that account. The annual depreciation expense returns to the Company's shareholders a portion of the costs of the capital assets. In a regulatory setting this return is commonly referred to as a return of equity. The remaining portion of the costs of the capital assets of the Company (net plant-in-service) is returned to the Company's shareholders in the future. The Company is permitted during this period to earn a return on the capital assets in rate base, commonly referred to as a return on net plant-in-service, a component of rate base. In a regulatory setting this return is commonly referred to as a return on equity.

B. Depreciation Study

Staff used the straight line method, broad group-average life procedure and whole life technique depreciation system for its depreciation study of the Company's capital assets. Staff has consistently used the whole life technique in developing depreciation rates that reflect expected average service lives. The whole life technique does not include an adjustment factor to address over- or under-accruals in the accumulated reserve for depreciation. Staff uses the following formula to calculate a depreciation rate for each plant account:

Depreciation Rate = (100 % -Net Salvage %) ÷ (Average Service Life).

This is consistent with the Commission's Depreciation Rate Formula from its Report and Order in The Empire District Electric Case No. ER-2004-0570. As shown in the formula, average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. The Staff calculated depreciation rates for each plant account based on the average service life and net salvage percentage determined applicable to each account, as shown for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Schedules 4-1, 4-2, and 4-3, respectively. That determination requires engineering experience and informed judgment and is addressed in detail below.

C. Average Service Life

For each plant account, the average service life (ASL) is the expected period, in years, of the useful service of each unit of property in that account, (e.g. electric poles), regardless of when that unit was first put into service—its placement date. An account's ASL is developed in four steps. The first step is to review historical mortality data and historical salvage/cost of removal data. The data are checked for reasonableness and to ensure sufficient data exist to perform a statistically significant analysis. In addition, Staff reviews the data to determine if retirements recorded in one historical database are also recorded in the other historical database. The second step is to gain familiarity with the facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with operations' personnel, engineers, accountants, and other depreciation experts. Current developments such as technological changes, environmental regulations, regulatory requirements, or accounting changes can all affect the average service life of property in an account. Different vintages of plant being manufactured from different materials, changes in installation practices, or the development of a life extending maintenance procedure are some examples of factors contributing to changes in average service lives. Difficulty in constructing new generation plant has led utilities to choose to spend the incremental costs of increasing the capacity of existing plants or extending the life of existing plants; i.e., expenditures at the Sibley Production Plant has extended the life of its original generating units.

The third step is to perform a statistical analysis of the retirement experience of each utility plant account, followed with analysis of the results for reasonableness for the type of plant in question. To evaluate the retirement experience of the Company's plant accounts, depreciation software used by Staff analyzes historical plant data by calculating the ratio of retirements to exposures by age, then solving for the percent surviving by age to develop a survivor curve for an account. The required data are plant additions in dollars by year, or vintage, and retirements from each vintage in dollars by year. The exposures at a given age are the dollars remaining from the various vintages that have lived to that age. The retirement ratio is the dollars retired during an age interval divided by the exposures at the beginning of that interval. The survivor ratio is then calculated by subtracting the retirement ratio from "1". Multiplying each successive survivor ratio by the percent surviving of the previous age will generate a survivor curve. This original survivor curve can then be smoothed and fitted to an empirically developed statistical model known as the Iowa curves. The Iowa curves are widely accepted models of the life characteristics of utility property. The system of Iowa curves is a family of 176 types of utility and industrial property. The curves were developed at the Iowa

Engineering Experiment Station at what is presently known as Iowa State University. The Iowa curves were first published in 1935 and reconfirmed in 1980. Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. The original survivor curve is mathematically and visually matched with various Iowa curves to determine which has the most appropriate fit, either for a significant portion of the curve or just a specified portion of the curve. The average service life of an account's original survivor curve is estimated as the area under the selected Iowa curve. The fourth step is using engineering experience and informed judgment to the aggregate of the first three steps in the process to assign an appropriate ASL for each plant account.

Staff's life estimates for GMO MPS production plant accounts include the Jeffrey Energy Center, located in Kansas, and the Sibley Generating Plant. The Company has an 8% ownership of the Jeffrey Energy Center. Staff's life estimates for GMO-L&P production plant accounts include the Lake Road Generating Plant and the Iatan I Generating Plant. The Company has an 18% ownership of the Iatan I Generating Plant. Because of data limitations with Jeffrey Energy Center production plant accounts, GMO- L&P electric accounts, GMO-L&P industrial steam production accounts, and GMO ECORP accounts, Staff recommends its life analyses of the GMO-MPS accounts be utilized to set depreciation rates for these respective functional accounts. Given that the plant assets in the respective functional accounts should be similar, the historical retirement activity should also be similar. The GMO ECORP accounts are the former Aquila, Inc. Corporate plant accounts. They will be discussed in more depth below. The short history of data and limited retirement history for the Jeffrey Energy Center accounts limit its statistical review. Data limitations for GMO-L&P referred to above include placements of vintages prior to 1979 in the data file are not recorded until 1979 and no retirements, from those vintages, recorded until 1979. This results in some plant being almost eighty years of age with no retirements occurring. The results of such data gaps can produce artificially long ASL's.

Staff recommends its life analysis of GMO-MPS account 366.00 Distribution Underground Conduit, be used for GMO-L&P electric account 357.00, Transmission Underground Conduit, as GMO-MPS does not have any assets in account 357.00.

Staff's review of the Company's booking of plant assets for the Crossroads Energy Center found that the Company is not booking these units consistently with other combustion turbines it is currently operating and including in rate base.

Staff recommends the Company review its unit property catalog for proper and consistent placement of these units, such that a depreciation analysis in the future reflects similar units of property in account 343.00, Prime Movers and account 344.00, Generators, respectively.

Staff recommends its life analyses of GMO-L&P industrial steam's distribution accounts be used to set depreciation rates for those accounts.

Staff recommends that the Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal.

As noted earlier the average service life is just one of two factors determining a given depreciation rate. The second factor, net salvage percentage, is discussed next.

D. Net Salvage Percentage

The second factor in determining a given depreciation rate is the net salvage percentage. Consideration is given to the future net salvage (or cost or removal) that property in an account may experience.

Net Salvage = Gross Salvage -Cost of Removal

Gross salvage is the recovered marketable value of retired plant. Cost of Removal is the cost associated with the retirement and disposition of plant from service. Negative net salvage occurs when the cost of removal exceeds gross salvage. A negative net salvage is commonly referred to as an expense or net cost of removal and a negative net salvage percentage is called a net cost of removal percentage. Today, most accounts experience a net cost of removal; therefore the net salvage percentage in the depreciation calculation is negative which results in an increase to overall depreciation expense.

Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage realized by the Company. This is consistent with the Commission's policy for net salvage from its Report and Order in The Empire District Electric Case No. ER-2004-0570. Staff performed rolling 5-year band analysis for deriving net cost of removal percentages. This review showed that in some accounts there was no recent history of costs and that, in other accounts, timing of retirements and costs produce unreliable estimates of net cost of removal percentages; i.e., GMO-L&P electric plant account 355.00, Poles and Fixtures, had an average net salvage percentage of negative 1434% for the 5-year period of 2003-2007. Five years prior, the account had an average net salvage percentage of positive 10% for the 5-year period of 1998-2002. From the earlier 5-year average to the most recent 5-year average the account experienced positive 8%, positive 2%, negative 9% and negative 8%, respectively. Future Net Salvage percentage estimates from the Company's 2008 Depreciation Study, performed by Dr. Ron White of Foster Associates, were also reviewed by Staff and are recommended by Staff to be used to develop Staff's proposed depreciation rates. For example, Dr. White's estimate of a negative 30% (rounded) for the L&P electric plant account 355.00, Poles and Fixtures, appears to be more aligned with the cost of removal trend actually occurring for this account. Additionally, net salvage percentages were capped by Staff at negative 100% by account. Both positions are consistent with those taken by Staff in the Company's 2005 rate case, Case No. ER-2005-0436. For all of the Company's production accounts, the net salvage percentage reflects an estimate of future interim cost of removal only, as terminal cost of removal is not collected until final retirement of a unit.

Dr. White noted on page 6 of the Company's 2008 Depreciation Rate Study, "[t]his study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Aquila-MPS and L&P (Electric and Industrial Steam) operations. The proposed rates are subject to approval by the Missouri Public Service Commission." Dr. White's study is an actuarial analysis and engineering study of utility property owned and operated by the Company, given the most recent utility property records. Staff notes that the Company has chosen not to adopt the results and proposed depreciation rates from their 2008 Depreciation Study, shown in Schedule 1.

Depreciation software uses the selection of a specific Iowa curve and net salvage percentage for each plant account to calculate the account's theoretical accumulated reserve for depreciation, discussed next.

E. Analysis of Accumulated Reserve for Depreciation

Another analysis performed with a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. This analysis illustrates whether prior depreciation estimates have differed significantly from actual experience. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date (December 31, 2007) to a theoretical accumulated reserve for depreciation, given the revised depreciation parameters selected for each account, as shown for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Schedules 5-1, 5-2, and 5-3, respectively. Staff used the December 31, 2007 reserve balances shown in the Company's 2008 depreciation study instead of reserve amounts shown in the Company's response to Staff Data Request No. 27, as the Company noted in an e-mail to Staff on January 22, 2009 that the balances in Data Request No. 27 include Retirement Work in Progress (RWIP) and the balances in the [2008] depreciation study do not (Schedule 6). Further discussion on RWIP can be found in the report section by Staff witness, Karen Herrington. (Similarly, the Company explains plant accounts waiting final unitization of a work order may cause a negative plant-in-service balance, i.e., GMO-MPS account 398.00, Miscellaneous Equipment, as noted in Schedule 7, and is demonstrative of the clearing process rather than an absolute balance.)

A depreciation reserve account is the amount for plant investment and net cost of removal that has been recovered in depreciation rates over the life of the capital assets, reduced by retirement amounts, costs of removal experienced, and transfers out, and increased by actual salvage proceeds collected, and transfers in. The aggregate of the depreciation reserve accounts is known as the accumulated reserve for depreciation. The theoretical accumulated reserve for depreciation amount can be viewed as the level of accumulated depreciation reserve that would exist today if the selected depreciation parameters had been used since the inception of placing plant in service. If the amount of the actual accumulated reserve for depreciation is more than the theoretical amount, an over-accrual is noted. Conversely, if the actual accumulated reserve for depreciation is less than the theoretical amount, an under-accrual is noted.

The need for, the magnitude of, and the timing of an adjustment should be based upon consideration of several factors: the characteristics of the account, the causes of the difference, and the year-to-year volatility of the accumulated provision for depreciation as well as the magnitude of the imbalance. Future service life cannot be estimated to a degree of certainty that guarantees that the actual life will not be different. In fact, the depreciation estimation process is dynamic and it is possible that the currently determined ASL that Staff is recommending will differ from the ASL that occurs. With the possible exception regarding ECORP noted below, no adjustment to the reserve is proposed by Staff at this time. After another depreciation study is conducted, trends in the over-accrual may be identified and appropriate steps, if necessary, can be implemented. Consideration of the ECORP accounts' accumulated reserve for depreciation should also be included in the balancing of the Company's over-accrual. ECORP accounts will be discussed below. Evaluation of these over-accrued reserves and ECORP under-accrued reserves should be made in future rate filings and, if appropriate, addressed by Staff at that time.

F. ECORP Accounts

In the Staff's direct testimony of the Company's last rate case, ER-2007-0004, Staff recommended that "the currently ordered depreciation rates be retained but that Staff perform a complete depreciation study in the Company's next rate case." The Company indicated it intended to complete its next full depreciation study by early 2008. The Company submitted a depreciation study to Staff in September 2008; however, its depreciation study of its corporate assets was never submitted and the Company never filed for a waiver of the requirement to do so.

Staff also noted in its direct testimony in the last rate case that there was a need to review the depreciation rates of the combustion turbines. However, Staff did not perform that review at that time due to a lack of sufficient operating experience, as the South Harper generating units were too new to have retirement history data, and the Greenwood generating units were leased units, thus their prior in-service experience was not included in actuarial plant data.

In the context of the present rate case, ER-2009-0090, Staff examined the depreciation parameters and plant accounts of the combustion turbines being operated by the Company.

The Company provided Staff historical mortality and salvage/cost of removal data in September of 2008 for all plant accounts, except its corporate plant accounts. Staff requested this data in questions (1) and (2) of Staff's Data Request No. 258 (Schedule 9-1). The Company's response to this data request was, "Data requested in questions 1 and 2 are prepared and incorporated as part of depreciation study projects. No corporate plant depreciation study was completed for 2007."

In the absence of historical mortality and salvage/cost of removal data for the Company's corporate plant accounts, Staff did a limited review of the activity and balances from corporate plant accounts and accumulated depreciation reserves from monthly entries in the Company's General Ledger and sub-ledger for November 2006 to December 2008 for these accounts, as provided in the Company's response to Staff's Data Request No. 258 (including supplemental requests, updates, and revisions) Schedules 9-1 through 9-6. Staff also reviewed information regarding corporate assets provided in the Company's response to Staff's Data Request No. 247 (including supplemental requests, updates, and revisions) Schedules 8-1 and 8-2 and Schedules 10-1 through 10-3 and data received in response to Staff's Data Request No. 27 regarding these accounts specific to the books of GMO-MPS and GMO-L&P Schedules 11-1 through 11-6 and Schedules 12-1 through 12-4).

Staff's limited review revealed several areas of concern that will be identified below.

The first concern is related to the Company's decision to cease use of the authorized depreciation rates for several of its corporate accounts, which caused an understatement of the reserve of approximately $4.2 million, and an equal overstatement of rate base.

Account 391.05, Computer Systems Development, account 394.00, Tools, Shop and Garage Equipment, and account 397.00, Communications Equipment are currently fully accrued. Staff recommends a 0% depreciation rate for these accounts (Schedules 3-1, 3-2, and 3-3). Reinstatement for the periods the Company failed to use the authorized depreciation rates creates an additional reserve of approximately $4.2 million for these accounts, equal to the amount noted above. [Reserve Adjustment Nos. R155.2, R157 R158, and R160, R127.2, R129, R130, and R132, and R95.2, R97, R98, and R100 for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively.]

The second concern is related to the early retirement of plant as a consequence of Aquila's acquisition by Great Plains Energy. The early retirement of plant creates a reserve deficiency in some of the ECORP accounts, as of September 30, 2008. This reserve deficiency is created when plant dollars are retired from the plant accounts and an equal amount is removed from the accumulated reserve for depreciation, without sufficient accrual over the life of the plant. In mass asset accounting, some plant may not reach the ASL of the account and other plant may reach a life extending beyond the ASL, resulting in, on average, the service life of the plant. However, when an unusual retirement occurs – such as when a utility's acquisition by another utility results in some plant no longer being needed and retired prematurely; a detriment to the current ratepayers is created if ratepayers are required to make up the deficiency. GMO's early plant retirement results in deficiencies of approximately $3 million for

GMO-MPS and approximately $1 million for GMO- L&P, as of September 30, 2008. Reinstatement of the approximately $4 million to the reserve for reserve deficiencies for these accounts will avoid detriment to the current ratepayers for transactions that occurred only because of GPE's acquisition of Aquila, Inc. [Reserve Adjustment Nos. R155.1 and R156.1, R127.1 and R128, and R95.1 and R96 for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively.] Further discussion on ratepayer detriment and these premature retirements of ECORP plant can be found in the report section by Staff witness, Charles R. Hyneman, CPA.

A review of the activity and balances for the reserves through December 31, 2008 shows that additional reserve deficiencies of approximately $1 million, in total, occur as additional plant is retired early through year-end. Currently, ECORP account 390.00, Structures & Improvements, has a negative amount of accumulated reserve for depreciation. And, as noted earlier, three of the five ECORP accounts for which Staff is recommending depreciation rates have a negative amount of accumulated reserve for depreciation, as of December 31, 2008. Identification of these negative ECORP reserves is the basis for Staff's consideration of balancing the Company's over-all over-accrual through a transfer of a portion of the $281 million over-accrual to the reserves for the ECORP accounts. As noted above, evaluation of these ECORP under-accrued reserves and the Company's over-accrued reserves should be made in future rate filings and, if appropriate, addressed by Staff at that time.

The third concern is related to the reserve deficiencies that exist specific to the books of GMO-MPS and GMO-L&P, of approximately $14.1 million and $4.7 million, respectively. These are not assigned to ECORP accounts, but are an amount reflecting an overstatement of Aquila, Inc.'s allocation of its corporate accumulated reserve for depreciation to Missouri where the corporate depreciation rates were higher than Missouri's authorized depreciation rates for corporate accounts.

A fourth concern is raised by the Company's failure to use authorized depreciation rates per 4 CSR 240-20.030, the failure of the Company to submit a depreciation study or request a waiver from the rules, and the Company's failure to submit a complete database per 4 CSR 240-3.175.

The fifth concern is related to the need for tracking of amounts accrued for the cost of removal component of the annual depreciation accrual. In its Report and Order issued January 11, 2005, in the remand of Case No. GR-99-315, the Commission directed "that Laclede Gas Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal." (Ordered Paragraph 6) This is consistent with the Commission's Report and Order in AmerenUE's Case No. ER-2007-0002 and in the Commission's Order Concerning Applications for Rehearing and Motions for Clarification or Reconsideration in The Empire District Electric Company's Case No. ER-2004-0570.

G. Recommendations

Staff recommends that the Commission order the depreciation rates proposed in Schedule 3-3 for GMO-L&P industrial steam. (Schedules 3-1 and 3-2 for GMO-MPS and GMO-L&P electric, respectively, will be addressed in the Company's Case No. HR-2009-0090.)

Staff recommends the Company be required to use the currently authorized Missouri depreciation rates for ECORP accounts until the effective date of this order and reflect the additional depreciation accrual on its books.

Accordingly, Staff recommends imputed depreciation accrual of approximately $4.2 million be added back to the reserves of the respective ECORP accounts For GMO the amounts to increase ECORP reserve include $7,142 for account 391.02, Computer Hardware, $4,168,503 for account 391.05 Computer Systems Development, $11,497 for Account 394.00, Tools, Shop, and Garage Equipment, and $34,036 for account 398.00, Miscellaneous Equipment. Staff also recommends this additional depreciation accrual be transferred to the reserve for ECORP account 390.00, Structures & Improvements, which is currently negative and, thus, under-accrued.

Staff recommends that to avoid a detriment to current ratepayers, reserve deficiencies of approximately $4 million for retirement of plant due to the Company's acquisition by Great Plain Energy be added back to the respective ECORP reserve accounts. For GMO-MPS the amounts to increase ECORP reserve include $7,331 and $2,958,887 for accounts 391.02, Computer Hardware, and 391.04, Computer Software, respectively. For GMO-L&P the amounts to increase ECORP reserve include $2,414 and $974,234 for accounts 391.02, Computer Hardware, and 391.04, Computer Software, respectively.

Staff recommends that the reserve deficiencies that exist specific to the books of GMO-MPS and GMO-L&P of $14,076,021 and $4,744,842, respectively, be included in the ECORP accumulated reserve for depreciation using a weighted average of each ECORP reserve account's balance as of September 30, 2008.

Staff recommends that both GMO-MPS and GMO-L&P electric keep a separate accounting of their amounts accrued for recovery of their initial investment in plant from the amounts accrued for the cost of removal.

Staff Expert: Rosella L. Schad

IX. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by the Staff consistent with the methodology used in L&P's last steam rate case, Case No. HR-2005-00450. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from the timing required by the Internal Revenue Service (IRS) in determining taxable income.

Current income tax reflects timing differences consistent with the timing required by the tax regulations. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different than the timing required by the IRS in determining taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

- Book Depreciation Expense

Subtractions from Operating Income:

- Interest Expense – Weighted Cost of Debt X Rate Base
- Tax Straight-Line Depreciation
- Tax Depreciation over Straight Line Tax

B. Straight Line Tax Depreciation

Annualized book depreciation is a result of multiplying the plant investment at September 30, 2008, the end of the update period used by the Staff for this proceeding, by the book depreciation rates being recommended by Staff witness Rosella L. Schad of the Engineering and Management Services Department. Straight line tax depreciation represents the tax deduction for book depreciation for a regulated utility for ratemaking purposes.

The IRS allows a regulated utility, like all corporations, to use an accelerated depreciation method in calculating its current income tax liability. However, with regard to a regulated utility, Congress intended for the additional cash flow (lower current income tax), resulting from an accelerated depreciation method, to be retained by the utility. As a result, under IRS rules for a regulated utility, the additional deduction resulting from the use of an accelerated depreciation method cannot be reflected in rates. Ratepayers receive the tax deduction for depreciation expense over the same period used for book accounting purposes.

Staff Expert: Paul R. Harrison

C. Deferred Income Tax Expense

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax as the result of the Internal Revenue Code (IRC), the timing difference is given "flow-through" treatment. When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

Staff Expert: Paul R. Harrison

D. Deferred Income Tax and Amortization

L&P steam deferred income tax reserve represents, in effect, a prepayment of income taxes by L&P's customers. As an example, because L&P is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as book-tax timing difference, and creates a deferral, or future liability of income taxes. The net credit balance in the deferred tax reserve represents a source of cost-free funds to L&P steam. Therefore, L&P steam's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base.

Staff Expert: Paul R. Harrison

X. Fuel Adjustment Rider

In the last steam heating case, HR-2005-0450, Aquila, Inc., Staff, Ag Processing, Inc., and the City of St. Joseph, Missouri came to an agreement regarding a fuel adjustment rider which is commonly referred to as the Quarterly Cost Adjustment or QCA. Staff was not involved in the negotiations regarding the QCA but supported the agreement. KCP&L-GMO has requested that the Commission allow it to continue the QCA with some modifications.

Section 386.266 RSMo. Supp. 2008 and Commission *Report and Orders* in four electric rate increase cases[12] have set standards for determining if electric utilities should be allowed rate adjustment mechanisms, i.e., fuel adjustment clauses. No such standards exist, either in statute or Commission orders, for steam heating utilities. The Commission's Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements rule (4 CSR 240-3.161) contains filing requirements for electric utilities which request, modify or continue a rate adjustment mechanism and submission requirements between rate increase cases

[12] Case Nos. ER-2007-0004 Aquila, Inc.; ER-2007-0002 Union Electric Company d/b/a AmerenUE; ER-2008-0093 The Empire District Electric Company; and ER-2008-0318 Union Electric Company d/b/a AmerenUE.

for electric utilities that are granted rate adjustment mechanisms. No filing and submission requirements exist for steam heat utilities that request or receive rate adjustment mechanisms to provide information necessary to evaluate the need for a rate adjustment mechanism.

Because no standards exist for determining the appropriateness of fuel adjustment riders for steam heating utilities and the support for continuing the QCA supplied by KCP&L-GMO is limited, Staff is not proposing a fuel adjustment mechanism. However, Staff would welcome the opportunity to participate in discussions among the parties regarding a rate adjustment mechanism for the steam operations of GMO.

Staff Expert: Lena Mantle

XI. Allocations Between Electric and Steam Operations

A. Application

GMO L&P only operates within the state of Missouri and has no federal jurisdictional customers so no jurisdictional allocations are necessary. However, since L&P provides both electric and industrial steam service an allocation is made between those two distinct operations. Staff used GMO's allocations to separate the operations between electric and steam for plant investment, accumulated depreciation reserve and expenses appearing in the income statement, Schedule 9 of the EMS run.

In order to develop a fully comprehensive cost of service analysis to identify the revenue requirements, all costs incurred by the Company for plant investment and income statement costs must be specifically placed in the electric and industrial steam served.

L&P specifically identifies the distribution plant between the electric and industrial steam operations. This is referred to as site specific or situs plant and Staff used 100% allocation factors for distribution plant and reserve to identify the entire distribution plant as specific to electric or industrial steam operations.

The FERC expense accounts found in the income statement (Schedule 9 of the EMS model) are broadly categorized as production, transmission, distribution and general. The allocation factors used to identify costs to a specific operation are based on the allocation factors used to allocate plant costs. L&P identifies allocation factors used to allocate the production plant accounts to their respective operations and are also used to allocate income statement costs for production and transmission expenses. Using the plant allocators to allocate costs to the specific operations is referred to as "expenses follow plant." The plant allocation factors used to allocate production and transmission plant costs are the same allocation factors used to allocate production and transmission expenses in the income statement. Production plant allocators are appropriate to use in the income statement for the production expenses. These expenses are associated with maintaining and operating the production plant. The allocations factors are also used to allocate the transmission plant and depreciation reserve and in turn, are used to allocate transmission expenses found in the income statement for the costs to maintain and operate the transmission network.

The common facilities or general plant are allocated based on a composite of the allocation factors used to identify production, transmission and distribution costs. Once the plant and depreciation reserve are allocated for production and transmission plant and site specific allocation factors for distribution plant costs, the state jurisdictions allocation factors for general plant are based on the composite for the production, transmission and distribution plant costs. The composite general plant allocation is used to allocate general costs in the income statement.

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

Staff Expert: Cary Featherstone

XII. Transition Cost Recovery Mechanism

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

In the Report and Order approving the acquisition (the Acquisition Order), the Commission concluded that it is not a detriment to the public interest to allow recovery of transition costs of the acquisition. In the Ordered Section of the Acquisition Order, the Commission directed the Joint Applicants to implement a synergy savings tracking mechanism utilizing a base year of 2006.

In the Acquisition Order, the Commission agreed that there was the potential for significant savings as a result of the acquisition and was supportive of the recovery of costs incurred in combining the operations of KCPL and Aquila (transition costs). Transition costs are those costs incurred primarily post-closing of the merger to integrate the operations of the two companies. While it did support recovery of these transition costs, the Commission did not specify the method by which this recovery was to be accomplished.

Specifically, in Ordered paragraphs 13 of the Acquisition Order, the Commission stated that "nothing in this order shall be considered a finding by the Commission of the value for ratemaking purposes of the transactions herein involved." Paragraph 14 further states that the Commission "reserves the right to consider any ratemaking treatment to be afforded the transactions herein involved in a later proceeding."

In this section of Staff's Cost of Service Report, Staff will describe its recommendation to the Commission regarding what it believes is the best approach to handle the issue of recovery of the transition costs related to this acquisition.

There are two (2) methods by which a utility can recover acquisition or merger transition costs; direct rate recovery and indirect rate recovery. Using the direct rate recovery method a utility would defer the acquisition costs, file for a rate increase, and amortize the deferred costs as an increase to cost of service. The indirect rate recovery approach the utility would defer the merger or acquisition costs, amortize the costs to expense, but not seek direct rate recovery. Under this approach, the costs would be recovered through regulatory lag whereby the utility's increased revenues and/or decreased expenses would be sufficient to cover the increased costs of the specific event, thus still allowing the utility the opportunity to earn its authorized rate of return.

Regulatory lag works similarly in the case of a merger or acquisition. As expenses that were embedded in rates set in the most recent rate case are no longer incurred by the acquired entity (for examples, salaries and benefits of the former Aquila officers and directors) excess rate recoveries over actual costs incurred accrue 100 percent to the utility's shareholders. These excess revenues collected in rates can be used to reduce or eliminate the cost of the merger or acquisition and the remaining excess rate recoveries will flow to shareholders as increases to net income.

In summary, regulatory lag is the mechanism that allows for the savings to naturally accrue to a utility, as the revenues in existing rates that were set to recover higher pre-acquisition costs (such as payroll, benefits, rents, board of director costs, property taxes etc.) no longer exist, and the savings that naturally accrue through regulatory lag over a period of time are often more than adequate to cover the costs incurred to combine the operations of the two entities.

Regulatory lag allows for a fair sharing of the benefits of a utility merger or acquisition. As a utility files rate cases during the time in which acquisition savings are being realized, the acquisition savings flow through to customers as the reduced expenses of the new entity are reflected in current rates. In the interim between rate proceedings, the new entity is allowed to retain the total net amount of any acquisition savings it can create. Regulatory lag allows, therefore, for a fair sharing of acquisition savings between customers and shareholders, and provides the appropriate incentives for the new entity to strive for more efficient and economic operations so it can create and provide to its shareholders increased profits. It also benefits customers as more efficient and economic operations lower costs which are reflected in rates.

The benefits of regulatory lag as a savings incentive mechanism and a description of how GPE/KCPL/GMO plans to use regulatory lag to recover acquisition savings was explained by Terry Bassham, Executive Vice President, Finance & Strategic Development and CFO, Great Plains Energy in a GXP/ILA (GPE/Aquila) Transaction Webcast on February 26, 2008.

> Under our revised proposal, the company will retain synergies through regulatory lag rather than seeking to establish a fixed up-front sharing to be recovered over time. Synergies would now simply be retained by the company until a rate case filing, and then flow through to customers as part of the traditional regulatory process. <u>This will provide a very simple approach to synergy</u>

> sharing and incent the company to move quickly to achieve synergies. (emphasis added)
>
> By using the normal regulatory process to recover synergies we will be utilizing the concept of "regulatory lag," which represents the time between when costs are measured and documented during a "test year" and when they are put into rates. As an example, for KCP&L's most recent rate case, our 2006 test year costs, updated in the third quarter of 2007 for certain "known and measurable" components, were used to determine what costs were to be included in rates that went into effect in January 2008. We will utilize this type of lag to allow shareholders to reap approximately 50% of the synergy savings in the Aquila transaction through the first five years.
>
> As the chart reflects, between rate cases, the Company retains, and shareholders keep the resulting benefit of, the synergies we achieve that are not reflected in rates. Then when we file a rate case, those savings will be reflected in our cost of service and provide lower rate increases for customers. Even once the initial savings are reflected, however, we will continue to generate additional synergies which would not flow back to customers until the next rate case.

In the current rate case, Staff is proposing that KCPL recover its transition costs through the regulatory lag approach to synergy savings described by Mr. Bassham. This approach recognizes that KCPL has already enjoyed the benefits of synergy savings through regulatory lag and these savings already realized can first be used to pay down the balance of unrecovered transition costs. Future synergy savings that accrue to KCPL after rates are set in this case can also be used to pay down the balance off the transition cost deferral and accrue as additional earnings to KCPL's shareholders.

As an example of how KCPL is currently benefiting from regulatory lag, KCPL's present rates (rates that are being paid today and will be paid until rates are changed in this case, at this time estimated to be around August 5, 2009) include all of the payroll and benefits costs of all of the former Aquila Networks - MPS and Aquila Networks - L&P employees who were terminated as of the acquisition closing date, July 14, 2008. This is a significant cost savings that can be applied to KCPL deferred acquisition transition costs. Because of this regulatory lag, the costs of severance packages in the amount of one-year salary will have been more than fully recovered when KCPL's new rates go into effect in August 2009. The same concept would apply to other costs that are currently being recovered in rates that no longer are being incurred, such as benefits costs, which average over 50 percent of payroll costs, rents and leases, which have been terminated, board of director fees, and insurance premiums. KCPL will have recovered a significant portion of its deferred transition costs even before rates from the current rate case go into effect. The fact that KCPL has already accrued acquisition savings which can be applied to the cost of the acquisition was confirmed by William Downey, President and COO, Great Plains Energy and KCPL in an EEI Conference Webcast on November 11, 2008:

> …As Mike talked about, the integration process that John is leading, we made tremendous progress there on achieving the synergy benefits that we have promised in this. These are very contiguous territories, and we planned very hard and long ahead of the merger. I will tell you that it has gone extremely smoothly both operationally, and in terms of the communities, and in terms of achieving some of the financial benefits. <u>In fact, in our September rate case filing in Missouri, we showed a net $23 million of operating synergies already achieved that will begin accruing to our customers when rates from this rate case go into affect in the third quarter of next year.</u> We will finalize actually that amount in a first-quarter 2009 true-up in our Missouri case. (emphasis added)

In addition to the regulatory lag benefits, KCPL has been and will continue to benefit until rates are changed in this case, KCPL will also continue to recover in rates set in this case costs embedded in KCPL's test year books and records that are not being adjusted and removed from cost of service in this case. It is with absolute certainty that these costs that Staff is not proposing to remove from this case, which are no longer being incurred by KCPL but will be included in utility rates until rates are changed in a future rate case, will continue to be recovered. The next KCPL and GMO rate cases are currently estimated by KCPL to conclude around August 2010 (KCP&L is currently planning to file its next rate case in September 2009). Staff is taking the approach that, while it is annualizing payroll and other costs in this case, it has not accomplished a thorough review of KCPL's and GMO's books and records to ensure that all costs that are no longer being incurred or will no longer be incurred because of the acquisition are removed from KCPL's and GMO's revenue requirement in this case.

Staff is adopting the regulatory lag approach to transition cost recovery in this case because it is the preferred approach to the direct rate recovery method. It not only benefits customers by recognizing the regulatory lag benefits that have already accrued to KCPL and reflecting the potential cost savings in this case, but it provides KCPL with an almost limitless opportunity to retain merger savings over the next ten (10) years.

Regulatory lag provides an incentive for utilities outside of a rate case to become more efficient and adopt the best practices of the combining entities to become a lower cost combined entity. The lower costs realized between rate cases will result in acquisition synergies that will be retained 100 percent by KCPL's shareholders.

The approach used by KCPL in this case is the direct rate recovery method. Through its Adjustment 78, KCPL is recognizing potential cost savings of a combined entity through adjustments such as payroll annualizations. It is also proposing adjustments to reduce per book amounts in accounts that are not included in its combined-company annualizations. As an offset to these adjustments, KCPL is proposing, a five-year amortization of its $34 million deferred transition balance allocated to KCPL, MPS and L&P operations.

As noted above, in paragraph 6c. of the Ordered Section of the Acquisition Order, the Commission directed the Joint Applicants to implement a synergy savings tracking mechanism utilizing a base year of 2006. Specifically, the Commission ordered that:

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

However, during meetings with KCPL personnel on the acquisition issue, Staff was advised that the 2006 baseline tracking mechanism ordered by the Commission was not the basis for KCPL's acquisition savings calculation in adjustment 78. Upon request of Staff, KCPL provided an incomplete draft version of a 2006 baseline "tracking mechanism." However, the combined 2006 baseline non-fuel Operations and Maintenance expense of $491,496,760 was adjusted by $46,125,970 or 9.4 percent before KCPL added a 3.1 percent inflation adjustment that results in a 2006 baseline, as adjusted and as inflated, of $584,763,556, or a 19 percent increase. In essence, the baseline year of 2006 was increased by almost $93 million by KCPL before any savings calculations are made.

As of the date of this filing of the Staff report, KCPL has not made any savings calculations in the 2006 base year tracking mechanism, and based on discussions with KCPL personnel, Staff is not expecting to receive an synergy savings calculation using the 2006 base year tracking mechanism for another 30 days. KCPL has advised Staff that it is waiting until proposed budgets are approved by its board of directors before it starts making savings estimates using the 2006 baseline, as adjusted and inflated by KCPL.

By choosing to use the direct method of transition cost recovery in this case, KCPL is forced to use a savings tracking mechanism to show that savings actually realized exceed the additional costs of combining the utilities. By additional costs, Staff is not referring to only the acquisition transition costs, but other potential cost increases that would not have been incurred by KCPL or GMO absent the acquisition and consolidation.

Such costs could increase salaries and union pay scales at KCPL beyond those that existed at Aquila, more expensive benefit programs, higher costs allocations of executive salaries to Missouri jurisdictional operations, a difference in focus developing cost-cutting efficiencies at the combined entities from the focus that existed at the pre-combined entities. There is a vast list of potential cost increases that may be incurred directly because of the acquisition that should be tracked under any transition cost rate recovery method proposed by KCPL and offset against the synergy savings calculation. While this would be a challenge for any company, it is especially a challenge for a company such as GPE/KCPL that reasonably argues that merger savings cannot be tracked with any degree of accuracy.

In her direct testimony in Case No. EM-2007-0374 (Exhibit 29), GPE's and KCPL's controller, Lori Wright explained that GPE did not recommend that acquisition savings be tracked. She said that in the best case there is a problem tracking savings with any degree of accuracy. The logical conclusion drawn from this statement is that in less than the best case scenario, it is not possible to accurately track acquisition savings. Ms. Wright testified as follows in Exhibit 29:

> Great Plains Energy does not recommend that synergy savings be tracked. Instead, Great Plains Energy recommends using the synergy savings identified in the Joint Application and the pre-filed testimony in support thereof. Tracking synergy savings with any degree of accuracy is problematic at best as business operations are not conducted in a static environment, but rather under constant change, including customer growth, technological improvements, etc. Tracking will become more difficult each successive year after the Merger.

To summarize, Staff is recommending to the Commission that it allow KCPL to recover its merger transition costs (a significant amount of which are currently being recovered through regulatory lag). This method is superior to the alternative direct rate recovery method which requires the use of a savings tracking mechanism which both Staff and the Company agree cannot be developed to produce accurate results.

Staff Expert: Charles R. Hyneman

XIII. Acquisition Detriment – Depreciation

As noted in the section on Depreciation, the Staff takes issue with MPS' accounting for certain ECORP assets that were retired as a result of its acquisition by Great Plains Energy. The Staff's position is that the accounting method and ratemaking proposal chosen by MPS results in an acquisition detriment as well as being inconsistent with the requirements of the FERC Uniform System of Accounts (USOA) for plant accounting. While the FERC USOA has no authority over the ratemaking decisions of the Commission, utility companies in Missouri are required to comply with the requirements of the USOA for bookkeeping purposes.

By removing the amount of the original cost of an asset that has not been fully depreciated from ECORP account 391.02 Computer Hardware and ECORP Account 391.04, Computer Software, Aquila has created a reserve deficiency or understatement of the associated reserve account balance as a result of the acquisition. Staff considers this a detriment of the acquisition and has made adjustments (R-155, R-156 MPS) to remove only the depreciated amount of this plant from the reserve. In addition, Staff believes that the USOA only allows the fully depreciated amount of the asset retired as a result of a merger or acquisition to be removed from the accumulated depreciation account for that asset. The Staff is aware that similar adjustments to the ones described above were made by MPS after the updated test year in this case and will update its position on this issue in its true-up recommendation to the Commission.

Staff Expert: Charles R. Hyneman

APPENDICES

Appendix 1: Staff Credentials

Appendix 2: David Murray Schedules

Appendix 3: Rosella Schad Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Steam Heating Service	))))	Case No. HR-2009-0092

AFFIDAVIT OF DAVID W. ELLIOTT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David W. Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 60 - 62 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David W. Elliott

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Steam Heating Service	))))	Case No. HR-2009-0092

AFFIDAVIT OF MICHAEL J. ENSRUD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael J. Ensrud, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 55 - 59; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael J. Ensrud

Michael J. Ensrud

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 51, 59 and 61-62; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

V. William Harris

V. William Harris

Subscribed and sworn to before me this 13th day of February, 2009.

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

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 52-54, 68-72, 76-77, 81 and 102-104; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Paul R. Harrison

Paul R. Harrison

Subscribed and sworn to before me this 13th day of February, 2009.

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

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AFFIDAVIT OF KAREN HERRINGTON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Herrington, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 46-49 and 74-83; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Karen Herrington

Karen Herrington

Subscribed and sworn to before me this 13th day of February, 2009.

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

Notary Public

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AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 72-73 and 107-115; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Charles R. Hyneman

Subscribed and sworn to before me this 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF KEITH A. MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith A. Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 63-68 and 73-74; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith A. Majors

Keith A. Majors

Subscribed and sworn to before me this 13th day of February, 2009.

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

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AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 104-105 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin
Notary Public

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OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Steam Heating Service	))))	Case No. HR-2009-0092

AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 7-46; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF BRET G. PRENGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Bret G. Prenger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 49-51, 79-80 and 83-84; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Bret G. Prenger

Bret G. Prenger

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Steam Heating Service	))))	Case No. HR-2009-0092

AFFIDAVIT OF ROSELLA L. SCHAD, PE, CPA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 84-101; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Rosella Schad PE, CPA
Rosella L. Schad

Subscribed and sworn to before me this 13th day of February, 2009.

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

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Steam Heating Service	))))	Case No. HR-2009-0092

AFFIDAVIT OF THOMAS A. SOLT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Thomas A. Solt, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 54; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Thomas A. Solt
Thomas A. Solt

Subscribed and sworn to before me this 13th day of February, 2009.

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

D. Suzie Mankin
Notary Public