MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

KCP&L GREATER MISSOURI OPERATIONS COMPANY

FILE NO. ER-2010-0356

Jefferson City, Missouri
November 17, 2010

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

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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 provides wholesale electricity to municipal customers under the jurisdiction of the Federal Energy Regulatory Commission (FERC). 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 is an affiliate of Kansas City Power & Light Company ("KCPL"). GMO was formerly known as Aquila, Inc. (and before that UtiliCorp United, Inc.). KCPL is also an "electrical corporation" and "public utility" that is subject to the jurisdiction of the Commission. GMO and KCPL collectively operate and present themselves to the public under the brand and service mark "KCP&L." GPE is a public utility holding company regulated under the Public Utility Holding Company Act of 2005, which was enacted as part of the Energy Policy Act of 2005. As a holding company, GPE does not provide electric service to retail customers.

GMO has approximately 312,000 customers of which about 273,500 are residential customers, about 38,000 are commercial customers and the remaining about 500 customers are industrial, municipal and other utility customers [Source: 2009 FERC Form 1] To serve these customers GMO owns 1,975 megawatts of generating capacity of which 892 megawatts is coal capacity (excluding Iatan 2), 1,019 megawatts of natural gas-fired combustion turbine capacity, 64 megawatts of oil fired combustion turbine capacity, and additional purchased power. [Source: GPE's 2009 Annual Report at page 23].

GMO's major environmental upgrades to its Iatan 1 generating units and GMO's share of the construction of a new baseload, coal-fired, generating unit designed to have 850 megawatts of capacity at the Iatan Station—Iatan 2 are the major drivers of the rate case.

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

MPS has filed for the following rate increases:

Case No.	Date Filed	Amount Requested	Amount Authorized	Effective Date of Rates
ER-2007-0004 (filed as Aquila entity)	July 3, 2006	$94.5 million (22% increase)	$ 45,253,654 million (11.64%increase)	June 3, 2007
ER-2009-0090	September 5, 2008	$ 66 million (14.4 % increase excluding any impact of the fuel clause)	$48 million (10.46% increase)	September 1, 2009
ER-2010-0356	June 4, 2010	$ 75.8 million (14.4% increase excluding any impact of the fuel clause)	Yet to be determined	May 4, 2011 (expected)

L&P has filed for the following rate increases:

Case No.	Date Filed	Amount Requested	Amount Authorized	Effective Date of Rates
ER-2007-0004 (filed as Aquila entity)	July 3, 2006	$22.4 million (22.1% increase)	$13,583,600million (12.79% increase)	June 3, 2007
ER-2009-0090	September 5, 2008	$ 17.1 million (14.4 % increase excluding any impact of the fuel clause)	$15 million (11.85% increase)	September 1, 2009
ER-2010-0356	June 4, 2010	$ 22.1 million (13.9% increase excluding any impact of the fuel clause)	Yet to be determined	May 4, 2011 (expected)

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

Staff Expert/Witness: Cary G. Featherstone

II. Executive Summary

Curt Wells, of the Commission's Utility Operations Division, and Cary Featherstone of the Utilities Services Division sponsor Staff's Cost of Service Report, Schedules and Accounting

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

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

As ordered by the Commission, and to timely and fairly present its direct case, Staff used actual historical information through the cut-off date of June 30, 2010, plus estimates for the impacts of the known major plant additions of Iatan 2 and an increase in GMO's fuel costs that takes effect January 1, 2011, for analyzing GMO's cost of service which Staff is referring to as its "Estimated True-up Case." Staff has determined Iatan 2 has met the in-service criteria and believes Iatan 2 is now “fully operational and used for service.” Therefore, although Iatan 2 was not “fully operational and used for service” by June 30, 2010, since Staff has performed a construction audit and prudence review of Iatan Project costs based on available information using a June 30, 2010 cut-off, Staff has a sufficient basis to include the impacts of Iatan 2 and the associated Iatan Common Plant on GMO’s cost of service.

There will be other changes in GMO’s investments and costs, from June 30, 2010 to December 31, 2010, and Staff has included an estimate in its direct case to account for them. In this filing, Staff presents its analysis of GMO’s revenue requirement based on the 2009 test year updated through June 30, 2010, with Staff’s estimate of the items that could easily be identified and quantified that will be addressed in the true-up. However, there are other cost increases expected to occur through December 31, 2010 that will be addressed only in the true-up. These will be reflected in the true-up using actual amounts for items such as payroll, payroll related benefits, pensions, and other costs. There are plant additions other than Iatan 2 which will be in service as of December 31, 2010. These plant investments will be included in the true-up audit.

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

Other plant additions will be made through the time of the true-up in this case causing costs to increase. Other costs will likely change materially during the true-up period, including payroll, payroll-related benefits such as pensions and medical costs. Maintenance costs will be updated to reflect the impacts of repairs of the distribution and transmission system.

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

- Rate of Return
- GMO's investments in Iatan Unit 2
- Remaining costs for the plant upgrades for environmental costs for GMO investment in the Iatan 1 AQCS (Air Quality Control System) not captured in its last rate case
- GMO's investment in Iatan Common Plant not captured in its last rate case
- GMO's fuel costs, including freight rate increase and purchased power costs, in particular the January 1, 2011 freight rate increase
- GMO's off-system sales margins from the firm and non-firm bulk power markets
- GMO's pension and other post-employment benefits (OPEBS) costs
- Acquisition savings and transition costs

Staff Expert/Witness: Cary G. Featherstone

III. Construction Audit

Staff performed a construction audit/prudence review of the Iatan Project-installation of air quality control systems on Iatan 1, construction of Iatan 2 and construction of plant serving both Iatan 1 and Iatan 2 (Common Plant)-- using a cost reporting cut-off date of June 30, 2010. Staff presented the results of that audit to the Commission on November 3, 2010, in Staff's Construction Audit and Prudence Review Of Iatan Construction Project For Costs Reported As Of June 30, 2010 that Staff filed in File Nos. ER-2010-0355 and ER-2010-0356. Based on that audit Staff has quantified many of its disallowances and the major impacts of the

Iatan Project on Staff's true-up revenue requirement recommendation for GMO; therefore, Staff is addressing them and relying on them for its current Estimated True-up Case revenue requirement recommendation for GMO. In addition to the Iatan Project GMO will have other plant additions and changes that will be fully captured in the true-up. Staff witness Charles R. Hyneman addresses the construction audit in his direct testimony being filed concurrently in this case.

Staff Expert/Witness: Cary G. Featherstone

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

GMO filed its general rate increase case on June 4, 2010, for its electric operations. GMO has different rates in two different areas – one in and about Kansas City, which was formerly served under the d/b/a Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as "MPS" and "L&P" in this report. GMO's filing reflects an annual increase in Missouri retail rate revenues of $75.8 million for MPS, representing a 14.4% increase (excluding the impacts on the fuel clause). GMO proposes an annual increase of $22.1 million for L&P, representing a 13.9% increase (excluding the impacts on the fuel clause). The Commission designated this rate case as File No. ER-2010-0356. GMO proposes a rate of return on equity of 11.0% applied to the 46.16% equity capital structure for GPE [page 3 of GMO Minimum Filing Requirements-- Application].

KCPL also filed a rate case on June 4, 2010, for its electric operations. This case has been designated as File No. ER-2010-0355. KCPL is proposing an annual increase in its rate revenues in the amount of $92.1 million, representing a 13.8% increase. KCPL request is based on a proposed rate of return on equity of 11.0% applied to the 46.16% equity capital structure for GPE [paragraph 5 of GMO Minimum Filing Requirements].

Staff Expert/Witness: Cary G. Featherstone

A. Test Year

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

Staff Expert/Witness: Cary G. Featherstone

B. Estimated True-up Case

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

> A true-up period of the 12 months ending December 31, 2010, and Iatan 2 and Iatan Common Plant cutoff period of October 31, 2010, is ordered, assuming that the actual in-service date of Iatan 2 is projected to occur no later than December 31, 2010. However, in the event that the in-service date of Iatan 2 is projected to be delayed beyond December 31, 2010, the true-up period would be moved to the last day of the same calendar month as the actual in-service date of Iatan 2 and the Iatan Common Plant cutoff period would be moved to two months prior the revised true-up date…
>
> If the true-up period is adjusted, KCP&L Greater Missouri Operations Company shall extend the effective date of its tariffs four months past the end of the true-up period; however, such adjustment shall not extend beyond an in-service date for Iatan 2 of March 31, 2011.

> KCP&L Greater Missouri Operations Company shall indicate by filing a pleading no later than October 6, 2010 if it seeks to adjust the true-up period.
>
> [Commission Order issued August 18, 2010, pages 2-3]

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

Staff Expert/Witness: Cary G. Featherstone

V. Rate of Return Section

A. Introduction

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

TABLE ONE: GMO'S ROR:

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: **8.50%**	**9.00%**	**9.50%**
Common Stock Equity	47.96%	-----	4.08%	4.32%	4.53%
Preferred Stock	0.00%	0.000%	0.00%	0.00%	0.00%
Long-Term Debt	47.42%	6.520%	3.09%	3.09%	3.09%
Equity Units	4.62%	12.351%	0.57%	0.57%	0.57%
Total	**100.00%**		**7.74%**	**7.98%**	**8.22%**

See Schedule 16

As contained in Table One, Staff recommends, based upon its expert analysis, a return on common equity ("ROE") of range of 8.50% to 9.50% and an overall ROR of 7.74% to 8.22% with a mid-point ROE and ROR of 9.00% and 7.98%, respectively. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-16. Additionally, with the exception of sources in which Staff simply extrapolated data and textbook references, supporting articles and/or reports are attached as Appendix 2, Attachments A - G. Staff will provide any additional supporting documentation upon the Commission's request.

B. Analytical Parameters

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

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

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

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

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

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

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

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

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[2] Additionally, today's utilities compete for capital in a global market rather than a local market. Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return GMO's shareholders may expect is equal to that required for comparable-risk utility companies.

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

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

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

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

C. Current Economic and Capital Market Conditions

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

1. Economic Conditions

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

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

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

Product ("GDP") growth rate to be in the range of 4% to 5%, of which approximately 2.0% is attributed to inflation.[6]

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

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

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets clearly indicate a lower cost-of-capital environment. If one were to

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

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

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

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Long-term interest rates, as measured by 30-year Treasury bonds ("T-bonds"), have decreased in recent months. The daily yield on 30-year Treasury bonds was 3.87% in October 2010, one of the lowest average yields since April 2009 (*see* Schedules 4-2 and 4-3). Long-term utility bond yields have also declined in this cycle, contrary to what occurred in the last cycle, dropping to a 40-year low in October 2010 of 5.14% (*see* Schedules 4-1 and 4-3). As of October 2010, the average spread between 30-year T-bonds (3.87%) and average utility bond yields (5.14%)[9] was 127 basis points, which is 27 basis points below the average such yields displayed in the period since 1980 (*see* Schedule 4-4). Recent utility bond yields have dropped to levels not experienced since the 1960s.[10]

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

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

[9] The 5.14% yield is based on an average from data obtained from BondsOnline.com. For utility bond yields cited by Staff prior to September 2010, Staff used Mergent Bond Record. Staff has canceled its subscription to Mergent Bond Record and will rely on data it receives from BondsOnline pursuant to a subscription agreement.

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

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

b. Utility Equity Markets

Over the nine months ending September 30, 2010, the total return on the Dow Jones Industrial Average was 5.6%, the total return on the Standard & Poor's 500 was 3.9%, and the total return on the Edison Electric Institute ("EEI") Index of electric utilities was 5.6% (*see* Appendix 2, Attachment D). More specifically on a non-market capitalization weighted basis, the total return for the nine months ended September 30, 2010 was 10.5% for EEI "Regulated" electric utilities, 7.0% for EEI "Mostly Regulated" electric utilities and -4.9% for "Diversified" electric utilities.

Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely to be more affected by general economic trends. The higher total return for "Regulated" electric utilities compared to broader markets and "Diversified" electric utilities implies that investors do not expect a significant economic recovery in the near future. Consequently, assuming investors in "Regulated" electric utilities have not increased their growth expectations for the regulated utility sector, these higher returns imply a decrease in the cost of equity for "Regulated" electric utilities.

D. GMO's and GPE's Operations

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

> Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:
>
> - KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (Receivables Company).
> - KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that primarily provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO wholly owns MPS Merchant Services, Inc. (MPS Merchant), which has certain long−term natural gas contracts remaining from its former non−regulated trading operations.
> - Great Plains Energy Services Incorporated (Services) obtains certain goods and third−party services for its affiliated companies.
> - KLT Inc. is an intermediate holding company that primarily holds investments in affordable housing limited partnerships.
>
> Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 23 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).
>
> The electric utility segment consists of KCP&L, a regulated utility, and, since the July 14, 2008, acquisition date of GMO, GMO's regulated utility operations which include its Missouri Public Service and St. Joseph Light & Power divisions. Electric utility serves over 820,000 customers located in western Missouri and eastern Kansas. Customers include approximately

> 724,000 residences, 95,000 commercial firms, and 2,300 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 85% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one−third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 104%, 119% and 130% of Great Plains Energy's income from continuing operations in 2009, 2008 and 2007, respectively.

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

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

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

Moody's senior unsecured credit rating for GMO is 'Baa3' and S&P's senior unsecured credit rating for GMO 'BBB' (*see* Appendix 2, Attachment E). Moody's senior unsecured credit rating for GMO's debt implies lower credit quality than that of S&P's senior unsecured rating for GMO's debt. Moody's rates KCPL's senior unsecured debt at 'Baa2', which implies better credit quality than the rating for GMO and also GPE, which is also rated 'Baa3' by Moody's. As can be surmised from the above information, Moody's gives more consideration to KCPL's stand-alone credit quality, whereas S&P considers both KCPL and GMO to be of equivalent credit quality due to their affiliation through GPE.

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

> The ratings on KCP&L Greater Missouri Operations Co. (GMO) reflect the consolidated credit profile of Great Plains Energy Inc. Great Plains' regulated subsidiaries include Kansas City Power and Light Co. (KCP&L) and GMO. The ratings also reflect the company's 'excellent' business risk profile and 'aggressive' financial risk profile. As of Dec. 31, 2009, the Kansas City-based Great Plains had about $3.7 billion of total debt outstanding.
>
> Through its regulated subsidiaries, Great Plains distributes electricity to about 820,000 customers in Kansas and Missouri. The company's electric generating capacity is approximately 6,100 megawatts (MW), and in 2009 about 80% of the energy generated was from coal and 17% from nuclear.
>
> The 'excellent' business risk profile reflects the company's pure regulated strategy, our view of the company's decreasing regulatory risk, and management's renewed commitment to credit quality. In 2009 the Kansas and Missouri Commissions ordered various constructive rate orders, increasing rates by a total of $218 million, or about 85% of what Great Plains originally requested. Additionally, we view the regulatory mechanisms including the fuel adjustment clauses for GMO and KCP&L (in Kansas only), and the allowance of additional accelerated depreciation to be credit supportive. Also in 2009, the company proactively reduced its dividend and issued equity, demonstrating its renewed commitment to credit quality...

Staff is not aware of any Moody's credit rating reports published specifically on GMO. However, as indicated before, Moody's does rate GMO's unsecured debt one notch below that of KCPL. It is Staff's understanding that Moody's rates GMO's unsecured debt 'Baa3' based on the fact that GPE guarantees GMO's debt. Otherwise, GMO's stand-alone financial risk would not support an investment grade credit rating.

F. Cost of Capital

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

1. Capital Structure

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

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

Staff believes that the consolidated-basis capital structure of GMO's publicly-traded parent, GPE, as of June 30, 2010, the end of the updated test year, is most appropriate for use as the rate making capital structure in this rate proceeding. *See* Schedule 6. This capital structure is appropriate because it reflects GMO's current financing and because the risk embedded in GPE's capital structure affects GMO's credit rating. However, embedded costs of capital issued subsequent to GPE's acquisition of GMO should be reviewed for possible risk adjustments due the increased risk associated with legacy GMO debt. Staff's recommended GMO ratemaking capital structure consists of 47.96% common equity, 47.42% long-term debt, and 4.62% equity units.[11]

[11] GMO's response to Staff DR No. 159 and SEC 2009 10-K Filing.

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

2. Embedded Cost of Debt

Consistent with Staff's recommendation in the last GMO rate case, Case No. ER-2009-0090, Staff recommends using The Empire District Electric Company's (Empire) embedded cost of long-term debt as a proxy for GMO's cost of debt. Empire provided its embedded cost of debt of 6.52 % as of June 30, 2010 in its recently filed rate case, Case No. ER-2011-0004. 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. 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. Staff believes the use of Empire's cost of debt as a proxy for GMO allows for the cost of debt embedded in rates to be based on true 3rd party debt transactions based on the continued issuance of debt financing rather than the use of funds that were raised due to forced asset sales. It is possible that Staff will make adjustments to Empire's embedded cost of debt when Staff files its Cost of Service Report in that case. If Staff does so, Staff may also revise the cost of debt it recommends be used for GMO's ROR.

3. Embedded Cost of Equity Units

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

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

Because the equity units consist of subordinated debt issued by GPE, the cost is directly impacted by GPE's credit quality, which has been negatively impacted by its acquisition of the former Aquila Missouri electric utility properties (GMO). Although the negative impact of the acquisition on GPE's credit quality would have caused a higher cost of capital under normal capital market conditions, this negative impact was magnified by the timing of the issuance in May 2009, a time when investors required a significant risk premium to invest in companies that were borderline investment grade. At the time of the issuance of the equity units GPE's senior unsecured credit rating was a 'BBB-'. Although GPE's credit rating was never downgraded due to its acquisition of GMO, Staff believes that its credit rating has definitely been suppressed because of the strain that GMO's legacy debt has placed on GPE's consolidated ratios. Because Aquila had a senior unsecured credit rating of 'BBB' before it started to experience financial difficulties associated with its non-regulated operations, Staff believes it is reasonable to adjust the cost of equity units to assume that GPE had a unsecured credit rating of 'BBB' rather than 'BBB-' at the time it issued the equity units.

Just as with estimating the cost of common equity, estimating what the cost of any type of capital might have been given a different risk profile requires some judgment. Just as with the estimation of the cost of equity it is usually reasonable to look to proxy companies to impute what the cost of the equity units could have been if GMO's cost of capital was not influenced by Aquila's failed non-regulated operations, which are still present in the cost of GMO's legacy debt and have an impact on GPE's consolidated credit quality. Additionally, because the equity units were issued in May 2009 (a time in which the additional cost to issue capital for a 'BBB-' entity compared to a 'BBB+' was higher than usual) it is important to look at equity units issued by other utility holding companies at approximately the same time. Staff was only able to find one utility holding company that issued equity units during the same approximate period. FPL Group issued equity units in May 2009 at a cost of 8.375%, which was 3.625% lower than the 12% that GPE paid. FPL Group had a senior unsecured rating at the time of 'A-', which is three notches higher than GPE's senior unsecured rating. Although the required return for each notch increase in credit rating typically increases at a decreasing rate (meaning that Staff's adjustment will probably be underestimated), Staff assumed that each notch required an additional 1.21% return (3.625/3). Consequently, Staff made a 1.21% downward adjustment to GPE's equity unit coupon rate of 12%, which resulted in an adjusted embedded cost of the equity units of 12.35%. While this cost still seems relatively high, the timing of the issuance of the equity units was during a period of much uncertainty in the market. For example, in the most recent Union Electric Company d/b/a AmerenUE (AmerenUE) rate case, Case No. ER-2010-0036, AmerenUE's embedded cost of debt included a 30-year First Mortgage Bond issued in March of 2009 with a coupon of 8.45%. This compares to Empire's recent issuance of a 30-year First Mortgage Bond at a rate of 5.20%, which was issued only slightly over a year later than AmerenUE's bond.

4. Cost of Common Equity

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

a. The Proxy Group

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

1. Classified as an electric utility by Value Line (61 companies);
2. Publicly-traded stock;
3. Classified as a regulated utility by EEI or not followed by EEI (26 companies eliminated, 35 remaining);
4. At least 70% of revenues from electric operations or not followed by AUS (10 companies eliminated, 25 remaining);
5. Ten years of Value Line historical growth data available (3 companies eliminated, 22 remaining);

6. No reduced dividend since 2007 (5 companies eliminated, 17 remaining);

7. Projected growth available from Value Line and Reuters (2 companies eliminated, 15 remaining);

8. At least investment grade credit rating (2 companies eliminated, 13 remaining);

9. Company-owned generating assets (2 companies eliminated, 11 remaining); and

10. Significant merger or acquisition announced in last 3 years (1 company eliminated, 10 remaining).

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

b. The Constant-growth DCF

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

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

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

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the weighted average of the 2010 (25%) and 2011 (75%) Value Line projected dividends per share (*see* Schedule 11) by the monthly high/low average stock price for the three months ending September 30, 2010 (*see* Schedule 10).[14] Staff weighted the Value Line projections in this manner in order to reflect the approximate amount of time remaining in 2010. Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.7%, unadjusted for quarterly compounding.

i. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share ("DPS"), earnings per share ("EPS") and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical

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

growth rates to be quite volatile.[15] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 9-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 9.50%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 11.80%. The average projected 5-year EPS growth rate yielded a non-sustainable growth rate of 5.97% (*see* Schedule 9-4, Column 6).

Due to the current volatility and wide dispersions present in Staff analysis of historical and projected DPS, EPS, and BVPS, Staff considered none of those methods to produce reliable indicators of long-term growth expectations. For this reason, Staff selected an alternative input, based upon Staff's expertise and understanding of current market conditions. Staff used a growth rate range of 4.0% to 5.0% in its constant-growth DCF, although Staff does not consider that figure to be sustainable for the electric utility industry in the long run. Since World War II, electric utility growth rates have been approximately half of achieved GDP growth. As noted previously, long-term GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities may be approximately 2.25%.

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

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or

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

economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[16] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for GMO.

A multi-stage DCF may use either two or three growth stages, depending on the situation being modeled. In either case, the last stage must use a sustainable rate as it is considered to last into perpetuity. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate estimate for the final stage because this growth is assumed to grow in perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[17]

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

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

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

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

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

set of assumptions, Staff's estimated cost of equity for the proxy group is approximately 8.70% to 9.40%, mid-point of 9.05%. Using the mid-point of Staff's assumed range of perpetual growth rates results in an estimated cost of equity of approximately 9.00%.

ii Stage one

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for purposes of estimating the growth in DPS in a single-stage constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analysis should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

iii. Stage two

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

iv. Stage three

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

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

v. Electric Utility Industry Long-term Growth Rates

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

vi. Perpetual Growth Rates Used in Investment Analysis

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

Additionally, one of the financial advisors hired by Aquila to provide a "Fairness Opinion" on a fair price to pay for the GMO properties provided their assumed perpetual growth rates in publicly-available documents filed with the SEC[21]. Blackstone Advisory Services L.P. ("Blackstone") estimated an implied perpetual growth rate of 3.4% to 4.8% for Aquila's (GMO's) cash flows after 2013. Blackstone estimated an implied perpetual

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

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

growth rate of 1.7% to 3.2% if Strategic Energy[22] was excluded and 1.7% to 3.4% if Strategic Energy was included. While estimated perpetual growth rates may change slightly over time due to shifts in expected economic and/or industry growth, Staff believes these provide a fair test of reasonableness of perpetual growth rates in a multi-stage DCF analysis or even a constant-growth DCF analysis for that matter. However, just as recent economic and financial events may have impacted the risk premiums investors require to invest in riskier investments, these events have probably also impacted investors views regarding potential long-term growth rates. Consequently, Staff believes that the perpetual growth rates used by these financial advisors would be lower if they were to perform their analysis in the current environment.

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

vii. Commission Preference for GDP Growth

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

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

then the estimated cost of equity is approximately 9.75%.

G. Tests of Reasonableness

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

1. The CAPM

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

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

Where: k is the expected return on equity for a security;

Rf is the risk-free rate;

β is Beta; and

Rm - Rf is the market risk premium.

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

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

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

2. Other Tests

a. The "Rule of Thumb"

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

b. Average Authorized Returns

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

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

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

39 decisions (first quarter – 10.29% based on nine decisions; second quarter – 10.55% based on ten decisions; third quarter – 10.46% based on three decisions; fourth quarter – 10.54% based on seventeen decisions).

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

Additionally, the fact that Staff's recommended ROR is similar to average authorized RORs even though Staff's recommended ROE is lower than average authorized ROEs implies that the embedded costs of capital Staff used in its overall recommended ROR are higher than average. GMO's higher embedded costs of capital can be attributed to both the costly equity units and most likely to a higher embedded cost of debt.

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

H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover GMO's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for GMO in the range of 7.74% to 8.22% (*see* Schedule 16). This rate was calculated by applying an embedded cost of long-term debt of 6.52% and a cost of common equity range of 8.50% to 9.50% to a capital structure consisting of 47.96% common equity, 47.42% long-term debt, and 4.62% equity units. Staff urges the Commission to accept its recommendation and in order to allow GMO to earn a fair return on its net rate base.

Staff Expert/Witness: David Murray

VI. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff recommends plant-in-service ("plant") and accumulated depreciation reserve ("reserve") balances be based on actual booked amounts as of the update period, June 30, 2010. This includes plant additions that have occurred since the test year ending December 31, 2009, and the related depreciation reserve balances. At the time of the true-up, adjustments to the plant balances Staff used for its direct filing will be updated to include amounts for plant additions that have become fully operational and used for service during the period of June 30, 2010, through December 31, 2010, the true-up cut-off date. Staff will also make a true-up adjustment to update for depreciation reserve balances related to those additions. Plant must be "fully operational and used for service," before it is appropriate to reflect that plant and its associated reserve in rates.

The plant for GMO for the period ending June 30, 2010 is identified on the Plant Schedule 3 of the Staff Accounting Schedules and the accumulated depreciation reserve as of that date is identified in the Depreciation Reserve Schedule 6 of the Staff Accounting Schedules.

During the analysis of GMO's plant reserve balances, Staff found GMO had made adjustments to the reserve account balances for retirement work in progress ("RWIP").[26] GMO removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates, but, as of June 30, 2010, had not removed the related reserve

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

for cost of removal and salvage. As a result, GMO's books overstate the reserve for this retired plant; therefore, Staff made an adjustment to remove from the reserve balances the plant that was no longer being used for service. Staff included a line item in the Accumulated Depreciation Schedule identifying the RWIP associated with Production, Transmission, Distribution and General Plant.

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

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

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

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

Staff Expert/Witness: Karen Lyons

1. Iatan 2 Common Plant

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

Staff Expert/Witness: Karen Lyons

2. Iatan 2 Plant

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

Staff Expert/Witness: Karen Lyons

B. Iatan Unit 2 and Common Allocation to MPS and L&P

Staff witness Lena Mantle supports the split of GMO's portion of Iatan Unit 2 based on a 100 MW allocation to L&P and a 53 MW allocation to MPS. Staff removed the amount of Iatan 2 Common plant on MPS's books as of June 30, 2010 to reallocate GMO's share of Iatan Unit 2 Common based on the aforementioned split. Staff Adjustments P-35.1, P-36.1, P-37.1, P-38.1, P-117.1, P-121.1, P-123.1, R-35.1, R-36.1, R-37.1, R-38.1, R-117.1, R-121.1, and R-123.1 in the MPS Accounting Schedules remove the June 30, 2010 plant and reserve balances for Iatan Unit 2 Common plant. Staff Adjustments P-35.2, P-36.2, P-37.2, P-38.2, P-41.2, P-42.2, P-43.2, P-44.2, P-45.2, P-46.2, P-117.2, P-121.2, P-123.2, R-35.2, R-36.2, R-37.2 R-38.2, R-41.1, R-42.1, R-43.1, R-44.1, R-45.1, R-46.1, R-117.2, R-121.2, and R-123.2 in the MPS Accounting Schedules and Adjustments P-29.1, P-30.1, P-31.1, P-32.1, P-35.2, P-36.2, P-37.2, P-38.2, P-39.2, P-40.2, P-67.1, P-69.1, P-71.1, R-29.1, R-30.1, R-31.1, R-32.1, R-35.1, R-36.1, R-37.1, R-38.1, R-39.1, R-40.1, R-67.1, R-69.1, and R71.1 in the L&P Accounting Schedules reallocate Iatan Unit 2 plant balances based on September 30, 2010 plant balances and the split of Iatan Unit 2 supported by witness Lena Mantle.

Staff Expert/Witness: Keith A. Majors

C. Generator Step Up (GSU) Transformer Transfers

For MPS GMO transferred the plant and reserve balances of the Jeffrey Energy Center Generator Step Up (GSU) Transformer from Transmission plant to Production plant. This adjustment has no effect on total plant. Staff has reflected this transfer as Adjustments P-25.1, P-104.1, R-25.1, and R-104.1 in the MPS Accounting Schedules. For L&P GMO transferred the plant and reserve balances of the Iatan 1 GSU Transformer to a separate account. This adjustment has no effect on total plant. Staff has reflected this transfer as Adjustments P-16.1, P-25.1, R-16.1, and R25.1 in the L&P Accounting Schedules.

Staff Expert/Witness: Keith A. Majors

D. Jeffrey Energy Center FGD Rebuild Project Adjustment

The Jeffrey Energy Center (JEC) is a coal-fired electric generating facility consisting of three 720 MW units, a total of 2,160 MW located in St. Marys, Kansas. GMO owns 8% of the JEC facility for a total of 172.8 MW which is assigned to MPS. Westar Energy, Inc. (Westar) is the operating partner of JEC and owns the remaining 92%. Units, 1, 2, and 3 were declared in commercial operation in 1978, 1980, and 1983, respectively. JEC environmental equipment includes cold-side electrostatic precipitators for particulate removal and limestone-based wet flue gas desulfurization (FGD) systems, or "scrubbers." The original FGD systems had not been in service for a number of years as JEC burned low sulfur Powder River Basin (PRB) coal to meet its SO2 permit limits without scrubbers.

In 2004, Jeffrey Received a Notice of Violation (NOV) from the U.S. Environmental Protection Agency (EPA). To avoid civil penalties and comply with tightening environmental regulations, Westar made the decision to rebuild the FGD systems on all three units.[27] Aquila,

[27] Staff DR 287, Case No. ER-2009-0090

now GMO, wrote a letter of concurrence supporting Westar's decision on February 16, 2007.[28] The "initial budget" of the three unit project was set at ** __________ ** with GMO's share at ** __________ **.[29]

** ____ __________________ . ** The following table outlines the project budgets, the dates of the budgets, and project contingencies, but does not include Westar tracked costs such as AFUDC:

** ____	__________ __________	__________	__________
________	__________	__________	__________
________	__________	__________	__________
________	__________	__________	__________
________	__________	__________	__________ **

** ____ ____ **

In the Commission's Order Regarding Construction And Prudence Audits of The Environmental Upgrades At Iatan 1, Jeffrey Energy Center And The Sibley Generating Facility dated April 15, 2009 in Case Nos. ER-2009-0090 and HR-2009-0092, the following appears at page 3.

> At the motion hearing for Case Nos. ER-2009-0090 and HR-2009-0092, GMO's counsel represented that improvements to the Sibley and Jeffrey facility were on time and on budget. . . .

The relevant transcript referenced by the Commission appears on the Transcript of Proceedings – Oral Argument dated April 6, 2009, Volume 10, page 28, lines 13-23.

> MR. ZOBRIST:
> …This case includes the improvements of Sibley and Jeffrey. They are on time and generally on budget, I understand.

NP

[28] Staff DR 297, Case No. ER-2009-0090
[29] Staff DR 287, Case No. ER-2009-0090

The information provided by GMO's counsel was in fact, not accurate. The most current cost report available at the time of the April 6, 2009 motion hearing was dated March 24, 2009 for costs through February 2009, attached as Appendix 3, Schedule 1. The final cost report for costs through August 2009 is attached as Appendix 3, Schedule 2. The total expended on the project through February 2009 was ** ____________ ** over the current budget with contingency, indicating the project at that time was ** ____ ** over budget. The table below shows the costs at February 2009 in addition to the costs from the final JEC rebuild cost report for data through August 2009 dated October 13, 2009, excluding Westar tracked costs:

** ________	________ ____ ________	________ ________	________ ________	________ ________ ________
________	________	________	________	________
________	________	________	________	________ **

The largest single vendor in budget amount was Powerplant Maintenance Specialists, Inc. (PMSI). PMSI was contracted to perform general construction work on the JEC rebuild project. The total contract executed on May 17, 2007 was for the amount of ** ________ **. Staff reviewed 20 change orders totaling ** ________ ** for a total lump sum contract price of ** ________ **.

Burns & McDonnell was contracted to provide engineering and construction management services for the JEC rebuild project. Burns & McDonnell produced monthly status reports concerning status of the project, scheduling, and budget. In Monthly Progress Report Number 27 for June 2008, the following statement appears on page 1-1 attached as Appendix 3, Schedule 3

NP

** **

** ** The addendum to the original PMSI contract is attached as Appendix 3, Schedule 4.

Burns & McDonnell, as part of its project management duties, prepared the contract specifications and evaluated the contractor bids to develop recommendations to Westar. In its recommendation for Specification 203 – General Construction in which Burns & McDonnell recommended PMSI, the following statement appears:

** . ** (Emphasis added).

The evaluation by Burns & McDonnell of the bids for Specification 203- General Construction is shown as Appendix 3, Schedule 5.

Westar and GMO did require other contractors on the JEC FGD rebuild project to obtain performance bonds. For example, the executed contract between Young Construction and Westar required Young Construction to furnish a performance bond up to at least the contract price increased for change orders. This also was the case for the contractor MJ Electric. The initial contract amount for these vendors for work on the JEC FGD rebuild project was

** ____________ **, contract dated April 17, 2007 and ** ___________ ** dated August 28, 2007, respectively. MJ Electric was the second highest construction contract in amount with PMSI being the largest at twice that of MJ Electric. The contract sections concerning surety, bonding, and insurance for Young Construction, MJ Electric, and PMSI are attached as Appendix 3, Schedules, 6, 7 and 8.

Westar and GMO in their ownership interest did not act appropriately or reasonably by exposing Westar, GMO, and consequently Missouri ratepayers to an inappropriate, unreasonable, and unnecessary level of financial risk. This inappropriate, unreasonable, and unnecessary financial risk resulted from Westar and GMO's decision not to require PMSI to obtain a performance bond. Had PMSI obtained a performance bond, Westar and GMO would have had proceeds to complete the contract or compensation for loss in the event of PMSI's non-performance.

To quantify Staff's proposed disallowance, the excess over the PMSI contract and approved change orders is reduced by a reasonable allowance for the cost of a performance bond. To quantify that allowance, Staff examined the performance bond cost for the second highest construction contract, MJ Electric. The initial contract for MJ Electric's scope of work was ** ___________ **. The performance bond amount listed on the bid comparison prepared by Burns & McDonnell was ** ________________ ** of the initial contract. Staff's conservative and reasonable estimate given the additional amount of the PMSI contract is ** _____** of the contract value plus the additional scope, or ** __________ **. This is Staff's estimation of the cost of a performance bond for PMSI. The net inappropriate, unreasonable, unnecessary amount is quantified in the table below from data from the final JEC FGD cost report for costs as of August 2009:

NP

**	
	**
Total Adjustment	$ 59,110,980
GMO's 8% Share	$ 4,728,878
GMO AFUDC	$ 102,771
Total Adjustment for Inappropriate Costs	$ 4,831,649

Staff Adjustment P-21.1 in the MPS Staff Accounting Schedule is the total adjustment for inappropriate and unreasonable costs related to the JEC FGD rebuild project.

Staff Expert/Witness: Keith A. Majors

E. Cash Working Capital

Cash Working Capital ("CWC") is the amount of cash necessary for a utility to pay the day-to-day expenses incurred to provide utility services to its customers. When the Company expends funds to pay an expense before its customers provide the cash, the shareholders are the source of the funds. This cash represents a portion of the shareholders' total investment in the

Company. The shareholders are compensated for the CWC funds they provide by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the funds they have invested.

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

The Cash Working Capital Schedule 8, of the Staff Accounting Schedules identifies the amount of cash working capital that was determined by using lead-lag study. Staff's CWC analysis results are reflected on the Rate Base Accounting Schedule 2, of the Staff Accounting Schedules of the section "Add to Net Plant In Service." Staff's CWC analysis results used in that schedule in the section entitled "Subtract From Net Plant" to derive the amounts indicated as Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

Prior to the GPE's acquisition of Aquila Inc, Aquila Inc. had developed 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. In 2009, GMO began negotiations with account securitization facilities to establish an account receivable contract. GMO was unable to establish an accounts receivable contract because it did not have at least three years of account receivable data as GMO. The Company provided the following explanation as to why it was unable to establish an account receivable program.

> "KCP&L GMO ("GMO") pursued the establishment of a $55 million accounts receivable securitization facility in 2009 through the Bank of Tokyo-Mitsubishi-UFJ ("BTM"). However, BTM notified GMO in July 2009 that its credit committee would not approve funding such a facility because there was not at least three years of standalone GMO accounts receivable data available post-acquisition by Great Plains Energy. Following BTM's rejection of the transaction, GMO approached JP Morgan to gauge their interest in such a facility and received the same feedback."

Failure to sell a portion of the Company's accounts receivable resulted in a longer revenue lag. Staff recommends reducing the revenue lag to reflect the number of days had the Company sold a portion of its accounts receivables. The change in the revenue lag can be found on Schedule 8, of the Staff Accounting Schedules. The accounts receivable program will be discussed in greater detail under the heading *Accounts Receivables Program.*

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

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

Staff reviewed the city ordinances for the Gross Receipt Tax ("GRT") to have a better understanding of how the tax was assessed and how it was collected. Staff found the tax was based on previous revenues on a semi-annual, quarterly or a monthly basis. Staff also reviewed the actual tax calculations made and submitted to the cities and townships for remittance of these taxes. For example, GRT accessed on a semi-annual basis with the payment due on January 31, 2009, would be calculated based on the revenues collected from July 1, 2008 through December 31, 2008. Staff calculated the time period from when GMO collects GRT from the customers to the time it remits the taxes to the taxing authorities. Based on this analysis, Staff determined that all municipalities served by GMO require that the GRT be remitted to those taxing authorities after the GRT amounts are assessed, billed to GMO's customers, and collected by the Company. Since the Company remits the GRT after it collects from its customers, these taxes are paid in arrears. The Company bills for the collection of the GRT along with the billing of electrical service and collects from the customers the same time as it collects for the provision of service. Customers are providing the cash for the GRT in advance which allows the Company to use these funds for a significant period of time prior to making payment to the municipalities. As a result of the analysis, Staff determined the GMO entities use the same methodology as Staff and treat the GRT as paid in the arrears. The calculations for the gross receipts taxes are reflected in the CWC schedule (Schedule 8, of the Staff Accounting Schedules) as lines 22-24 for MPS and line 17 for L&P.

Staff Expert/Witness: Karen Lyons

F. Prepayments

Prepayments are the costs a company incurs and pays in advance of receiving goods or services. Prepayments are treated as an asset and are reflected in the utility's rate base. Staff included in its rate base calculation amounts for all prepayments of goods and services that the Company requires to provide electric utility service to its customers.

Staff examined all of MPS and L&P's prepayment account balances dating back to their previous rate case (ER-2009-0090) through June 30th, 2010, on a month-by-month basis. Based on this review, and the variability in the monthly account balances, Staff determined the prepayment levels to be included in GMO and L&P's rate bases. These amounts were determined using methodologies selected dependent upon whether the accounts under review were exhibiting discernable upward or downward trends. In situations in which there was no discernable upward or downward trend in the monthly balances, Staff calculated an average based on balances for the 13-months ending June 30th, 2010. On accounts that did exhibit a noticeable upward or downward trend Staff also used the most recent account balance (June 30, 2010).

Staff did not include prepayments related to gross receipts taxes. While MPS and L&P include gross receipts taxes as a prepayment, Staff believes that these costs are actually paid in arrears and as a result Staff excluded these taxes from prepayments. The cash flow impact on the entities for gross receipts taxes is reflected in Staff's Cash Working Capital (Schedule 8 of Staff's Accounting Schedule). Staff's pre-payment calculation is shown on Accounting Schedule 2 of the Staff Accounting Schedules.

Staff Expert/Witness: Bret G. Prenger

G. Customer Deposits

Customer deposits are the funds required to be provided by certain customers taking electrical service from the Company. These funds are deducted from the Company's rate base because these funds are cost-free funds received by the Company. The amount reflected for customer deposits on Rate Base Schedule 2, of the Staff Accounting Schedules, is the most current Missouri Jurisdictional customer deposit balance as of June 30, 2010. For L&P, a 13- month average was used because the account balance exhibited a constant state of flux. For MPS, the June 30, 2010 balance was used, as Staff noticed no consistent upward or downward trend. In addition to the amount deducted from rate base for customer deposits, because customers are paid interest for the use of the funds they provide to the Company on a cost free basis an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903 included in Income Statement Schedule 9, of the Staff Accounting Schedules.

Staff Expert/Witness: Bret G. Prenger

H. Customer Advances

Customer advances are funds typically provided by developers to the Company in order to ensure that the Company builds electric infrastructure in areas that have potential for future development. These advances are also used by the utility to establish electric service for potential future customers without investing a substantial amount of money at the risk of the utility and its other customers. Customer advances are included in the rate base as an offset, reducing the amount of overall investment that customers must supply as a return to the utility, included in Rate Base Schedule 2, of the Staff Accounting Schedules. The amount of customer advances reflected on that schedule represents a 13-month average for L&P and the last known June 30, 2010 balance for MPS.

Staff Expert/Witness: Bret G. Prenger

I. Customer Deposits – Interest Expense

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

Adjustments: L&P: E-117.2 and MPS: E-111.2

Staff Expert/Witness: Bret G. Prenger

J. Fuel Inventories

1. Coal Inventory

Staff included in the rate base of MPS and L&P an amount for coal inventory based on the results obtained from Staff's production cost model (fuel model). Among other things, Staff uses its fuel model to determine an appropriate mix of generation unit and purchased power utilization to match the normalized native load of the Company. In doing so, Staff obtained from the fuel model an annual amount of tons of coal burned by each coal-fired generation unit during the normalized updated test year. For GMO, Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. Staff then multiplied this average daily burn by an appropriate number of days of coal inventory for each generation unit and added an estimated level of basemat coal. Basemat coal is the bottom portion of the coal pile that is not usable as fuel due to contamination by soil, clay and other contaminants. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated for the units of MPS and the units of L&P, and the aggregated amount for MPS and L&P separately, multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown as coal inventory in Rate Base Schedule 2, of the Staff Accounting Schedules.

Staff Expert/Witness: V. William Harris

2. Oil and Fuel Additive Inventories

Staff used 13-month averages to determine the inventory levels for oil and other fuel inventories. 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. This approach is consistent with how GMO determined its inventory levels for these items.

A 13-month average inventory reflects the Company's actual experience for the entire 12-month test year period by including a beginning inventory and an ending inventory. For example, if the test year were a calendar year it would begin with January 1 and end with December 31. A 13-month average 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 the Company's actual experience because they ignore the impact of the period from January 1 through January 30.

MPS Rate Base Schedule 2, of the Staff Accounting Schedules, reflects Staff's inventory levels for coal, oil and other fuel inventories for MPS. Staff's inventory levels for L&P's coal, oil and other fuel inventories are shown in L&P Rate Base Schedule 2, of the Staff Accounting Schedules.

Staff Expert/Witness: V. William Harris

K. Material and Supplies

Materials and supplies represent an investment in inventory for items such as spare parts, electric cables, poles, meters, and other miscellaneous items used in daily operations and maintenance activities by GMO (MPS and L&P) to maintain its production facilities and electric system. Staff reviewed the monthly balances for materials and supplies over the last several years because the account balances varied greatly depending on each individual account. Staff examined the accounts individually and determined an appropriate measure to most accurately predict the ongoing future of a particular account. Methodologies included: 13-month average and ending balances, included in Rate Base Schedule 2, of the Staff Accounting Schedules.

Staff Expert/Witness: Bret G. Prenger

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

See the discussion of these items in Section VIII. B. 6. - FAS 87/Pension Expense and Section VIII. B. 7. - FAS 106/OPEBs Expense

Staff Expert/Witness: Paul R. Harrison

M. Accounting Authority Orders

The Commission issues accounting authority orders (AAO) in response to applications made by utilities to the Missouri Public Service Commission (Commission) seeking a specific accounting treatment for a category of expense. Generally, AAOs are tied to a desire by the utility to seek ratemaking treatment of an extraordinary cost in a future rate proceeding.

MPS currently has two AAOs, issued in Case Nos. ER-90-101 and ER-93-37. The unamortized balances for each of these AAOs are included in GMO's rate base. In case, ER-90-101, MPS Sibley rebuild project, the Commission ordered a 20 year recovery of the costs with the unamortized balance included in rate base. This AAO deferral began in October 1990 and ended in September 2010. Since the AAO has ended, an adjustment is necessary to remove the unamortized balance from the 2009 test year. In 1993 two additional AAOs were granted by the Commission for the Sibley rebuild project, Case No. ER-90-101 and Case No. ER-93-37. The Commission ordered a 20 year recovery for each of these AAOs. In Case No. ER-90-101, the deferral began in July 1993 and will end in June 2013. In Case No. ER-93-37 the deferral began in June 1993 and will end in May 2013. Staff included the unamortized balance in rate base for each of these AAOs.

In 2007, the city of St Joseph, Missouri was struck by a significant ice storm. St Joseph, Missouri is L&P. That ice storm caused considerable damage to the Company's distribution plant in the L&P territory. The Company filed an application with the Commission for an AAO to defer the excessive maintenance and operational costs associated with the 2007 storm. That docket was designated Case No. EU-2008-0233. The Commission granted the AAO and ordered that the amortization of the costs associated with the storm begins on January 1, 2008 and end on January 1, 2013. This AAO does not receive rate base treatment. Since the 2009 test year included the annual amortized amount, no adjustment was necessary.

Staff Expert/Witness: Karen Lyons

N. Iatan Unit 2 Construction Accounting

On August 5, 2010, KCP&L Greater Missouri Operations Company (GMO) filed an Application for an accounting authority order (AAO) that would allow GMO to treat the Iatan 2 project under "construction accounting" until the effective date of the rates approved in this rate case, File No. ER-2010-0356. The Commission established File No. EU-2011-0034 to receive responses to GMO's Application. The Commission granted this AAO in its Order Granting Accounting Authority Order dated September 28, 2010.

"Construction accounting" is defined in GMO's Application dated August 4, 2010 on page 2:

> 4. "Construction Accounting", as used in this Application, is defined as: "Construction Accounting will be the same treatment for expenditures and credits consistent with the treatment for Iatan 2 prior to Iatan 2's commercial in service operation date. Construction Accounting will include treatment for test power and its valuation consistent with the treatment of such power prior to Iatan 2's commercial in service operation date with the exception that such power valuation will include off-system sales. The AFUDC rate that will be used during this period will be consistent with the AFUDC rate calculation in Paragraph III.B.1.g of the KCPL Experimental Alternative Regulatory Plan, as amended by the July 26, 2005 Response To Order Directing Filing of the Signatory Parties in Case No. EO-2005-0329, [i.e., a 2.5% or 250 basis point reduction in the equity portion of the AFUDC rate (or a construction accounting equity cost rate of 7.7%)]. *See* July 28, 2005 *Report and Order* in Case No. EO-2005-0329, page 18. The amortization of the amounts deferred under this Construction Accounting method will be determined by the Commission in the 2010-11 Rate Case.

The July 29, 2010 Stipulation And Agreement / Proposed Procedural Schedules recommended and the Commission's August 18, 2010 Order Approving Nonunanimous Stipulation And Agreement, Setting Procedural Schedule, And Clarifying Order Regarding Construction And Prudence Audit adopted an update cutoff for the direct cases of parties other than KCPL and GMO of June 30, 2010. As of June 30, 2010, Iatan Unit 2 had not achieved commercial in service operation. At the time of the true-up in this case, Staff will reflect the "fully operational and used for service" status of Iatan Unit 2 and appropriate Construction Accounting, including the test power calculations for GMO's share of Iatan Unit 2.

Staff Expert/Witness: Keith A. Majors

O. Engineering Reviews

1. Scope

The Engineering Analysis Section of the Energy Department, Utility Operations Division, is responsible for and conducts Engineering Reviews of major electric utility construction projects. The Engineering Review consists of two activities — monitor project construction progress and review construction project change orders.

To monitor the progress of the project during construction, Engineering Staff makes periodic field visits to the site. Ideally, Engineering Staff begin making field visits at the on-set of the construction and continue visits until a project is determined to meet the criteria to be considered "fully operational and used for service." During a field visit, Engineering Staff meet with construction and company personnel to review the overall progress of construction, review documents related to changes affecting the project, including documents of changes in the schedule and changes in costs, and to receive updates of safety-related aspects of the project.

Engineering Staff review construction project change orders associated with the project for the following:

- To understand the reason for the change at the point in time when the change order was issued;
- To determine whether the change corrected an engineering-related problem, resulted in a better design, or improved the operation or construction of the plant; and
- To determine whether the change resulted in a safety concern, caused unnecessary construction, or caused unnecessary duplication of facilities or work.

In any particular Engineering Review the number of field visits to monitor construction progress, the number of meetings with construction and company personnel and the number of construction project change orders that Engineering Staff reviews vary depending on a number of factors, including the project type, the project size, the project location, and the availability of Engineering Staff to perform the Engineering Review.

Other than as it relates to the foregoing list, the Engineering Staff's review of change orders does not include a review of events preceding issuance of a change order, any change in construction project costs due to a change order, or any other action or inaction by the company which resulted in a change order.

During an Engineering Review, the Engineering Staff discuss the change orders with company and construction project personnel to understand the reasons for the change orders. In addition, the Engineering Staff review contracts, agreements, purchase orders, drawings, and correspondences related to the change orders. If Engineering Staff determine there is an engineering concern with a change order, such as an unnecessary coal conveyor, the Engineering Staff would share its concern with the Commission's Auditing Staff and consult with Staff management to determine the appropriate response to take to address the concern.

Staff Expert/Witnesses: Shawn Lange/Dave Elliott

2. Activities and Conclusions related to the Staff Engineering Review of Sibley Unit 3 SCR Project

Based on its Engineering Review of change orders provided by KCP&L Greater Missouri Operations Company (GMO), Engineering Staff[30] found no engineering concerns with any of the Sibley Unit 3 Selective Catalytic Reduction (SCR) project change orders reviewed.

GMO has full ownership of the Sibley generating plant located in Sibley, Missouri. The SCR project included installing new equipment and upgrading the existing equipment to improve NO_2 ("nitrogen dioxide") removal.

[30] Engineering Staff that performed this review were Shawn Lange and David Elliott.

Engineering Staff visited the Sibley site on May 14, 2008, August 28, 2008, September 3, 2008, November 19, 2008, and January 15, 2009, and participated in a conference call on March 3, 2009.

During these site visits Engineering Staff toured the construction site, discussed construction progress and future milestones, and reviewed any documentation relevant to construction progress or change orders the Engineering Staff reviewed. The conference call with Sibley plant personnel and project personnel was held to discuss follow-up questions about the construction project.

Based on prior construction project engineering review experience, Engineering Staff selected $50,000 as an appropriate benchmark minimum level of cost change associated with a change order to limit the number of change orders Engineering Staff reviewed, but still allow Engineering Staff to review the change orders for major work. Therefore, Engineering Staff requested from GMO copies of all approved change orders over $50,000. As of May, 2009, Engineering Staff received from GMO copies of 5 change orders having associated cost changes of $50,000 or more.

The Engineering Staff discussed the 5 change orders with GMO construction project personnel and plant personnel to understand the reasons for each of the change orders. In addition, the Engineering Staff reviewed contractor/vendor contracts, purchase orders, drawings, and correspondences related to the change orders. Engineering Staff found no engineering concerns with any of the Sibley Unit 3 Selective Catalytic Reduction (SCR) project change orders reviewed.

Staff Expert/Witness: Shawn Lange

3. Activities and Conclusions related to the Staff Engineering Review of Jeffrey Energy Center Scrubber Project

Based on its Engineering Review of Westar Energy, Inc. (Westar) change orders provided by KCP&L-Greater Missouri Operations Company (GMO), Engineering Staff[31] found no engineering concerns with any of the Jeffrey Energy Center scrubber project change orders reviewed.

GMO has an 8% ownership share of the Jeffrey Energy Center generating plant located near St. Marys, Kansas. Westar has the majority ownership, 92%, and is the operator of the plant. The plant consists of three coal-fired 720 MW generating units. The scrubber project included installing new equipment and upgrading the existing equipment to improve SO2 removal on all three of the generating units.

Because of the distance to the Jeffrey Energy Center and GMO's small percentage ownership, Engineering Staff only visited the site once during the scrubber construction project. Engineering Staff visited the Jeffrey site on November 20, 2008, and on July 22, 2010. In addition the Engineering Staff participated in a conference call on January 20, 2009. The last visit in July, 2010 took place after testing was completed to determine if Jeffery Energy Center Unit 2 scrubber met the in-service criteria.

During these site visits Engineering Staff toured the construction site, discussed construction progress and future milestones, and reviewed any documentation relevant construction progress or change orders the Engineering Staff reviewed. The January 20, 2009, conference call with Jeffrey Energy Center plant personnel and project personnel was held to discuss follow-up questions about the construction project.

[31] Engineering Staff that performed this review were David Elliott and Shawn Lange.

Based on prior construction project engineering review experience, Engineering Staff selected $50,000 as an appropriate benchmark minimum level of cost change associated with a change order to limit the number of change orders Engineering Staff reviewed, but still allow Engineering Staff to review the change orders for major work. Therefore, Engineering Staff requested from GMO copies of all approved change orders with a value change (increase or decrease) of $50,000 or more. As of November, 2008, Engineering Staff received from GMO copies of 54 change orders having associated cost changes of $50,000 or more.

The Engineering Staff did an initial review of the 54 change orders and determined that 5 were non-engineering issues, such as insurance coverage, temporary support personnel, equipment leasing, purchase order/accounting corrections, negotiated settlements, and project schedule delays. Keith Majors of the Auditing Staff reviewed these change orders. The Engineering Staff discussed the remaining 49 change orders with Westar construction project personnel and plant personnel to understand the reasons for each of the change orders. In addition, the Engineering Staff reviewed contractor/vendor contracts, purchase orders, drawings, and correspondences related to the change orders. Engineering Staff found no engineering concerns with any of the Jeffrey Energy Center scrubbers project change orders reviewed.

Staff Expert/Witness: David W. Elliott

P. In-Service Determination

<u>1. Jeffrey Energy Center Unit 2 Scrubber 2 In-Service</u>

Jeffrey Energy Center (JEC) is a generating plant located near St. Marys, Kansas. It is composed of three 720 MW subcritical, pulverized coal fired generating units and is operated by the majority owner, Westar Energy, Inc., with KCP&L-Greater Missouri Operation Company (GMO) owning eight (8%) of the plant. In 2008-2009 Sulfur Dioxide Reduction Equipment, referred to as a scrubber was installed on all three of JEC's generating units. However, only two scrubbers (Units 1 and 3) were operational and Staff recommended that the two scrubbers be declared "fully operational and used for service" during the last rate case, Case No. ER-2009-0090. In this case Staff recommends that the Commission declare the Unit 2 scrubber "fully operational and used for service."

The in-service criteria to be used for the scrubber were developed by Staff and GMO and agreed to in Case No. ER-2009-0090. These criteria appear in Schedule TSH2010-1 of the GMO Witness Terry Hedrick's pre-filed direct testimony in this case. Staff used these in-service criteria to determine whether the Jeffrey Unit 2 scrubber, is "fully operational and used for service."

The specific in-service criteria and Staff's evaluation notes are attached as Appendix 4 to this Report. Based on Staff's on-site observation of Jeffrey Energy Center Unit 2 scrubber, supplemented by Staff's review of Jeffrey Energy center Unit 2 scrubber test data, and start-up documentation, Staff concludes that the JEC Unit 2 scrubber has successfully met all of the in-service criteria and was "fully operational and used for service" as of July 22, 2010.

Staff Expert/Witness: David W. Elliott

VII. Income Statement – Revenues

A. Rate Revenues

1. Introduction

This section describes how Staff determined the level of GMO Operating Revenues for both MPS and L&P. Since the largest component of operating revenues result from rates charged GMO's retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates GMO charges its Missouri retail customers for electricity may be appropriate. Because GMO has two different sets of rates in different parts of its service area (the areas formerly served by Aquila as Aquila Networks-MPS and Aquila Networks-L&P, which in this report are, for convenience, called MPS and L&P, respectively), Staff determined operating revenues and cost of service for each of the two different parts of GMO's service area, *i.e.*, MPS and L&P.

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

Rate Revenue: Test year rate revenues consist solely of the revenues derived from GMO's charges for providing electric service to its Missouri retail customers. GMO's revenues for MPS and L&P are determined by each customer's usage and the (per unit) rates that are applied to that usage. In Missouri different rates apply to different times of the year (summer vs. winter); different types of charges (demand, energy); and to customers in different rate classes.

Staff Expert/Witness: Curt Wells

2. The Development of Rate Revenue in this Case

To determine the level of MPS and L&P rate revenues, Staff has applied standard ratemaking adjustments to test year (historical) usage (kWh) and revenue data for both MPS and L&P service areas. The intent of these adjustments to test year Missouri rate revenues is to determine the level of revenue that the Company would have collected from the customers in each service area on an annual basis, under normal-weather or climatic conditions, based on information "known and measurable" by the end of the update period. In this particular case, the test year is calendar year 2009 and the update period ends June 30, 2010.

Rate revenue for both MPS and L&P has been developed and summarized in two different ways: one way is by type of regulatory adjustment; and a second way is total rate revenue by rate class. The Rate Revenue Summary Tab of the Staff Accounting Schedules summarizes rate revenue both ways, i.e., by type of adjustment and by rate class. The rate classes shown for the MPS service area are Residential (RES), Small General Service (SGS), Large General Service (LGS), Large Power Service (LPS), Special, and Lighting. For the L&P service area classes shown are Residential (RES), General Service (GS), Large General Service (LGS), Large Power Service (LPS), and Lighting. Staff workpapers provide the source numbers and analysis for the individual rate codes, and present a much more detailed version of the summary table.

This report briefly describes seven adjustments Staff made to test year billed rate revenues:

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

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

Staff Expert/Witness: Curt Wells

3. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normalization

i. Weather Normals Used in Weather Normalization

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

The time period used in determining the normal values of weather variables is the 30-year period (January 1, 1971- December 31, 2000) as used by National Oceanic and Atmospheric Administration (NOAA)[32]. NOAA, states that "climate normal is defined, by convention, as the arithmetic mean of a Climatological element computed over three consecutive decades." However, NOAA's daily normals are derived by statistically fitting smooth curves through monthly values, and as a result they do not contain daily variation in temperature for weather-normalizing electricity use. The weather normalization of electric usage requires *daily* temperature normals, because electricity usage varies differently at extreme daily temperatures than it does at mild daily temperatures. Consequently, Staff adjusted its daily data so that the monthly average of the daily data equals the NOAA monthly average.

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

[32] National Oceanic and Atmospheric Administration

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

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

Actual temperatures do not smoothly increase or decrease during the year.[33] This impacts the daily loads which, in turn, impacts the dispatch of generating units. To imitate daily fluctuations, these ranked normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test year and the month of the year that the rank normally occurs on.

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

Staff Expert/Witness: Seoung Joun Won

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

ii. Weather Normalization of kWh Usage

Staff estimates what energy usage would have been to calculate the revenue MPS and L&P (collectively, GMO) would have billed their respective customers and what the load requirements of those customers would have been given a year of normal[34] temperatures. Normalization is conducted on the Residential, Small and Large General Service classes because a significant amount of the electrical energy consumed by customers in these classes is used for climate control which responds to the weather and to daily changes in the weather.[35]

Winter in the 2009 test year included both cooler-than-normal and warmer-than-normal months. Summer 2009 was cooler-than-normal. Staff reviewed GMO's input data, weather normalization methodology and the resulting weather adjustments and agrees with and, therefore, adopts GMO's weather normalization adjustments for the MPS Residential, Small and Large General Service classes and the L&P Residential, Small General Service and Large General Service Classes.

Staff does not adopt GMO's Large Power Class' weather normalization for either MPS or L&P. Relative to the other classes, the Large Power Class consists of a small number of customers whose operations greatly differ from one another in the amount of electricity used and how it is used across the hours of the day. As a brief and not all-inclusive example, this class includes hospitals and hotels, universities and schools, large *box-stores*, metal products manufacturers and recyclers, refrigeration companies providing ice and cold storage services, airports, an air force base, and food product and milling companies. Many of these industries' activities are more sensitive to the economic cycle and/or time-of-year than to the weather.

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[34] For a full explanation of normal weather and how it is calculated, refer to Staff witness Seoung Joun Won's discussion in section 5. a ii., Weather Normals used in Weather Normalization, immediately preceding.

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

Because the usage of these customers was highest in July and August – not because it was hot but because it was July and August - the presence of such businesses in the class increases the class' overall electric usage making the class appear to be more weather sensitive than it is. The treatment of this class' data is fully discussed in *Section E, Large Customer Annuualization and Rate Switching*.

Staff Expert/Witness: Walt Cecil

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

Based on the analysis by Staff Witness Walt Cecil, Staff accepted the Company's weather normalization adjustments for kWh usage. Weather normalization only affects the energy usage of each existing customer and thus only affects those charges directly related to kWh usage. Weather normalized rate revenue results from applying billing rates to billing units including this adjusted kWh usage.

Staff Expert/Witness: Curt Wells

b. Annualization for Rate Change

One important determinant of rate revenues in this case is the annualization of current rates (effective September 1, 2009). Test year (calendar year 2009) rate revenues reflect rates prior to September 1, 2009 and current rates after September 1, 2009 as established in Case No. ER-2009-0090. Thus, test year revenues for MPS and L&P are understated by the difference between the amount that was actually billed to customers prior to current rates effective September 1, 2009 and the revenue that would have been realized by the Company if the current rates had been in effect throughout the entire test year. Staff computed annualized revenues on September 1, 2009 rates for each class by applying September 1, 2009 rates to test year annualized billing units for each class. This adjustment affected all rate classes in MPS and in L&P.

Staff Expert/Witness: Curt Wells

c. 365-Days Adjustment For Weather Sensitive Classes

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

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than or less than the number of days for the same-named calendar month. For the example given above, the usage is for 30 days (June 8 through July 8) even though the revenue month is July which has 31 days. When revenue month usage is totaled over the year, the resulting revenue year will include usage from the immediately prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain more than or less than 365 days. Therefore since the costs and expenses are for a calendar year, Staff calculates a normalization adjustment to bring the revenue year into a 365 day interval. This adjustment is referred to as a 365-days adjustment.[36]

Staff performed a 365-days adjustment for MPS usage and L&P usage. Staff calculated the difference between the weather normalized calendar month sales over the test-year, and the weather normalized revenue month usage over the test-year. The 365-days adjustments for both MPS and L&P were provided to Staff witness Alan Bax to be used in the calculation of the energy jurisdictional allocator. Staff witness Curt Wells used the 365-days adjustments to adjust the revenues of the weather normalized class revenues months to the 2009 calendar year.

Staff Expert/Witness: Walt Cecil

d. 365-Days Revenue Adjustment For Weather Sensitive Classes

Staff calculated its revenue adjustment for weather sensitive classes by allocating the "365-days" kWh adjustment proportionately to the appropriate revenue month weather normalized kWh usage for each class and then applying current rates. The difference between the revenues calculated in this way for each class, and the test year revenues for the class, determined the amount of the 365-days adjustment.

Staff Expert/Witness: Curt Wells

e. 365-Days Adjustment for Large Power

The 12 bill cycles making up the test year for each customer may or may not cover 365 days. For the Large Power (LP) rate group, Staff makes a monthly adjustment to those customers whose test year revenue month usage does not contain 365 days by either adding the appropriate number of days of average kWh usage when there were less than 365 days of usage, or subtracting the appropriate number of days of usage when there were more than 365 days of

[36] 365-days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

usage. Appropriate rates are applied to each month's adjusted usage to obtain revenue. The differences between the revenues produced by the days adjusted usage and the actual usage are the "days" revenue adjustments.

Staff Expert/Witness: Curt Wells

B. Customer Growth

Customer growth adjustments were made to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue, which would have occurred if the number of customers taking service at the end of the update period (June 30, 2010) had existed throughout the entire test year. KWh sales were then adjusted by the same percentage as revenue. For MPS, customer growth was calculated for the MO815, MO860 and MO870 Residential rate classes, MO710 and MO711 Small General Service rate classes and the MO720 Large General Service rate class. For L&P, customer growth was calculated for the MO910, MO915, and MO920 Residential rate classes, and MO930 and MO931 Small General Service rate classes, and the MO940 Large General Service rate class. All growth was calculated using customer levels as of June 30, 2010.

Staff Expert/Witness: Amanda C McMellen

C. Additional Revenues from Customer Growth During the Update Period

For this direct testimony filing, Staff updated all elements of revenue, expense, and rate base over the 2009 test year level for any known and measurable changes through June 30, 2010. A review of the pertinent facts at June 30, 2010, indicates that MPS and L&P have experienced an increase in its revenues since the end of the test year, due to overall growth in the number of its utility customers. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff has employed the following method of computing the annualized level of increased revenue from customer growth at June 30, 2010. For each customer rate group, the customer level during each month of the test year is compared to the level at June 30, 2010, and the monthly change in level is computed. This growth in customers is then multiplied by the weather-normalized revenue per customer experienced for that month of the test year. The total growth in revenues is arrived at by performing this comparison and multiplication for each month of the test year, and then summing the results. In short, this approach assumes that the revenue pattern experienced in each month of the test year will recur, on a weather-normalized basis, factored up (or down) in accordance with the growth (or decrease) in customer numbers at June 30, 2010.

The only retail customer rate group for which this approach is not taken is the Large Power group. With respect to Large Power customers, energy consumption and revenue patterns vary significantly across this group of customers, making it necessary to examine the history of each customer on an individual basis, and to adjust the test year revenue level accordingly. Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, General Service, and Large Power customers in order to provide the annualized level at June 30, 2010. The adjustments for retail customer growth other than Large Power are Rev-2.9 for MPS and Rev-2.9 for L&P.

Staff Expert/Witness: Amanda C McMellen

D. Customer Growth in Usage

Staff adjusted test year kWh sales for customer growth by allocating the additional rate revenue provided by Staff witness Amanda McMellen to each billing determinant of each rate code experiencing growth.

Staff Expert/Witness: Curt Wells

E. Large Customer Annualization and Rate Switching

The general intent of an annualization is to re-state test year kWh results as if conditions known at the end of the update period had existed throughout the entire test year. It is customary for Staff to annualize each of the very largest customers on an individual basis to reflect any major growth or decline in kWh usage and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers. A major component of the large customer annualization process consists of gathering 12 months of representative usage and revenue data for each large customer active at the end of the update period.

During this particular test year ten customers in MPS and two customers in L&P were in their respective LPS rate class for less than the full year. These customers are new or have switched from one rate class to another ("Rate Switchers"). Of these customers, seven customers entered and three left the MPS Large Power class; for L&P, two customers left Large Power. While the overall effect of rate switching on kWh usage nets to zero (one class' increase exactly equals the other class' decrease), the effect of the switching was to reduce overall rate revenues.

Those customers who switched <u>into</u> the LPS rate class were handled as part of the Large Customer Annualization. Those customers that switched <u>out of</u> the LPS class during the test year and update period were removed from the Large Power class completely and into the LGS class.

Staff Expert/Witness: Curt Wells

<u>1. Customer Discounts</u>

EDR: The Economic Development Rider (EDR) provides for discounts to be "paid" to large customers (in the form of credits on their electricity bill) who locate or expand operations in GMO's service territory—the same EDR is available to MPS and L&P customers. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. Depending upon which contract year the customer is in, the discount can be as high as 30% (year 1) to as low as 10% (year 5). For the Large Power class, Staff annualized the credits by first removing the credits from those customers receiving them, applying the rate change annualization, and then applying the next year's credit percentage to this annualized revenue. These discounts are included in the determination of both MPS and L&P revenues because fostering economic development is assumed to be a benefit to all ratepayers.

Curtailable Demand Rider: Curtailment Demand Rider provides credits to customers that agree to curtail at least 200 kW of their summer (June 1 through September 30) peak load when requested by GMO up to twenty (20) times in any contract year. Since these discounts benefit all ratepayers by reducing the need for additional production capacity, they are included in the determination of GMO's revenues.

MPower Rider: This rider is also designed to reduce customer load during peak periods. Customers that are able to curtail at least 25 kW during the peak season and agree to a fixed number of curtailment events receive a payment/credit for participating. Since these discounts help to defer future generation capacity and improve supply, they benefit all ratepayers and are included in the determination of GMO's revenues.

Staff Expert/Witness: Curt Wells

2. Annualization and Normalization Results

Normalized and annualized kWh usage was used in the development of NSI. Rate revenue, for both the MPS and L&P service areas, with adjustments, are at the Rate Revenue Summary Tab of the Staff Accounting Schedules.

Staff Expert/Witness: Curt Wells

F. Bulk Power Sales

1. Deferred Sales from SO_2 Emissions Allowances

GMO receives SO_2 emission allowances ("SO_2 allowances") from the U.S. Environmental Protection Agency ("EPA"). GMO uses these allowances to serve its native load customers. In addition to these allowances, the EPA also holds back a certain number of allowances for the specific purpose of having allowances available for auction. When the allowances are sold at the annual EPA auction, the proceeds are forwarded to GMO. Under the FERC Uniform System Of Accounts ("FERC USOA"), proceeds from the sales of SO_2 emissions allowances are recorded in FERC Account 254, the FERC USOA regulatory liabilities account. For ratemaking purposes, amounts recorded as regulatory liabilities reduce a utility's rate base, i.e., the net amount in FERC Account 254, after any appropriate adjustments, is an offset to rate base.

Staff has included in its direct case the balance of Account 254 on June 30, 2010, as an offset to rate base. This approach is consistent with the treatment in the last two GMO/Aquila rate cases, Case Nos. ER-2007-0004 and ER-2009-0090. The rationale for treating these SO_2 emissions allowances in this manner is to acknowledge that, through rates, GMO's customers have paid for GMO's production facilities that create these SO_2 emissions allowances.

Staff Expert/Witness: V. William Harris

2. Off-System Sales

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

Prior to the acquisition of MPS and L&P by Great Plains Energy in 2008 GMO, formerly Aquila, experienced significant and profitable levels of OSS and OSS margins, as illustrated by the table below. Since the 2008 acquisition, GMO's off-system sales levels and OSS margins have significantly decreased.

MPS OSS levels and net margins since 2002 are as follows:

12-month period ended	MPS Total Account 447030 Off-System Sales	MPS Account 447030 Net Margin	MPS Net Margin %
12/31/2002	** __________ **	** __________ **	9.36%
12/31/2003	** __________ **	** __________ **	20.25%
12/31/2004	** __________ **	** __________ **	28.99%
12/31/2005	** __________ **	** __________ **	46.98%
12/31/2006	** __________ **	** __________ **	16.60%
12/31/2007	** __________ **	** __________ **	14.16%
12/31/2008 GPE acquired Aquila July 14, 2008	** __________ **	** __________ **	21.93%
12/31/2009	** __________ **	** __________ **	(20.80%)
06/30/2010	** __________ **	** __________ **	(26.54%)

NP

L&P Off-system sales levels and net margins since 2002 are as follows:

12-month period ended	L&P Total Account 447030 Off-System Sales	L&P Account 447030 Net Margin	MPS Net Margin %
12/31/2002	** ________**	**________ **	30.85%
12/31/2003	** __________**	**__________**	61.89%
12/31/2004	** __________**	**__________**	66.32%
12/31/2005	** __________**	**________**	42.15%
12/31/2006	** __________**	**_________**	61.97%
12/31/2007	** __________**	**__________**	62.12%
12/31/2008 GPE acquired Aquila July 14, 2008	** __________ **	**_________**	61.21%
12/31/2009	** __________**	** _________**	(73.55%)
06/30/2010	** __________**	** __________ **	(54.20%)

Since the acquisition, there have been significant downward trends in OSS levels and net margins for both MPS and L&P. Because MPS experienced abnormal levels in 2004 and 2006 and L&P recorded abnormal levels in 2002 and 2004, Staff could not normalize off-system sales using an average of three or more consecutive years. As a result, for its direct filing Staff adjusted the test year in this case using a two-year average of the year prior to the acquisition of MPS and L&P (2007) and the 2008 acquisition year. Staff will continue to monitor GMO's off-system data as it becomes available during the true-up period ending December 31, 2010. At the end of the true-up period, Staff may propose other appropriate adjustments as necessary.

Staff Expert: V. William Harris

<u>3. Removal of Inter-Company Off-System Sales Revenue</u>

This adjustment eliminates inter-company off-system sales revenues that were recorded during the test year between MPS and L&P. An inter-company transaction is a transaction between corporations that are members of the consolidated group. The source for the eliminated off-system sales for both MPS and L&P is the actual per book amounts for calendar year 2009.

Staff Expert: V. William Harris

<u>3. Other Revenue Accounts</u>

Staff reviewed the amounts MPS and L&P have included in its cost of service calculation for Other Revenues, which include forfeited discounts[37] , miscellaneous service revenues, rent from electric property, replacement of damaged meters, disconnect service charge, temporary installation profit, and other transmission service revenues, among others. The analysis of these amounts included a review of the revenues over the last ten and a half years through June 30, 2010. In Staff's opinion, the test year Other Revenues amounts appeared to be representative and reasonable of an annualized level of revenue for each respective category and, therefore, do not require adjustment. Staff will examine these revenue accounts again during its true-up audit through December 31, 2010.

Staff Expert/Witness: Amanda C McMellen

VIII. Income Statement - Expenses

A. Fuel and Purchased Power Expense

<u>1. Fixed Costs – Fuel Adders</u>

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

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[37] Forfeited discounts are also referred to as late payment fees.

Fuel adders for natural gas include non-labor fuel handling and natural gas pipeline reservation charges.

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

Staff Expert: V. William Harris

2. Fixed Costs - Purchased Power Capacity Charges

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

Staff adjustments E-50.1 and E-55.1 annualize purchased power demand charges for MPS and L&P respectively, based on existing capacity contracts in effect. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff reviewed each of these contracts and determined the appropriate costs per megawatt hour and the amount of megawatts purchased. Staff included the costs reflected in GMO's capacity agreements that were in effect on June 30, 2010.

Staff Expert: V. William Harris

3. Purchased Power – Energy Charges

Staff adjustment E-74.2 annualizes purchased power energy charges based on Staff's fuel model results. These purchased power energy charges represent the energy GMO purchases on the spot market and through contracts to meet the system load requirements of its retail electric customers. Staff witness David W. Elliott is responsible for determining the appropriate amount of power purchased and the proper price for this power.

Staff Expert: V. William Harris

4. Removal of Inter-Company Off-System Sales Costs

Consistent with the removal of inter-company off-system sales revenues from cost of service for both MPS and L&P, Staff is making an adjustment to eliminate the inter-company off-system costs associated with fuel and purchased power that were recorded during the 2009 test year.

Staff Expert: V. William Harris

5. Variable Costs

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

The second scenario, as described in Staff's Executive Summary, uses test year inputs ending December 2009, as updated through December 31, 2010. This scenario captures Iatan Unit 2, and updated fuel prices supplied by Staff of the Commission's Auditing

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Department. Under this scenario Staff estimates the variable fuel and purchased power expense for GMO to be ** __________ **.

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

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

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

Model inputs calculated by Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. Staff relied on

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GMO responses to data requests for factors relating to each generating unit. These factors include: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Firm purchased power contract information, such as hourly energy available and price, are also inputs to the model.

Staff Expert/Witness: David W. Elliott

a. Coal Prices

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. Staff's proposed coal prices reflect GMO's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect on June 30, 2010. There is a significant rail freight rate increase expected January 1, 2011. Consequently, Staff plans to include a projected level for this fuel increase in Staff's true-up case.

Staff Expert: V. William Harris

b. Natural Gas Prices

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

Staff Expert: V. William Harris

c. Oil Prices

Staff used the actual cost GMO paid for its most recent fuel oil purchases. GMO burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. As a result, GMO purchases fuel oil infrequently. The limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because GMO does not make purchases during the majority of the year. 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 and purchased power expense on a going forward basis.

Staff Expert: V. William Harris

6. Spot Market Prices

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

Staff used in this case a procedure developed by the Engineering Section of the Commission's Energy Department in 1996 that is described in "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market," (March 18, 1996) which is Attachment x to this report. The method uses a statistical calculation based on the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.

The actual hourly non-contract transaction prices for KCPL and GMO during the update period were obtained from the data that the Companies supplied to Staff in compliance with 4 CSR 240-3.190 and are the prices used as price inputs by Staff in its calculation. Staff used the combined data from both KCPL and GMO to reflect the market that exists in this region. The calculation yields a spot energy price for each hour of the year. This data set containing 8760 hourly spot energy prices is then used as one of the inputs to Staff's RealTime® production cost model.

Staff Expert/Witness: Erin L. Maloney

7. Allocation of Fuel and Purchased Power Costs

Staff used a balancing methodology to allocate fuel and purchased power costs between MPS and L&P. Staff developed this methodology in Case No. ER-2009-0090, GMO's most recent rate case.[38] This method fairly distributes off-system sales revenue as well as fuel expenses, and purchased power expenses between MPS and L&P.

The inputs to Staff's allocation methodology are the hourly normalized loads (net system input) for MPS and L&P provided by Staff witness, Walt Cecil and the hourly output of the RealTime® production cost model (based on those hourly loads) provided by Staff witness David W. Elliott. The output of the RealTime® production cost model is the annual variable cost of fuel and the net purchased power energy costs. The output of the allocation methodology is the percentages of those costs for MPS and L&P. Staff performed ten iterations, eliminated the highest and lowest results, and then calculated the average. The results were provided to Staff witness, V. William Harris for use in annualizing fuel expense for MPS and L&P.

The allocation methodology assumes that MPS and L&P are each obligated to use the least expensive resources available that each owned prior to the merger to serve their respective native loads. (The South Harper CTs, Prudent CTs 4 and 5, and 53 MWs of Iatan 2 have been assigned to MPS, 100MWs of Iatan 2 has been assigned to L&P) . The method makes several passes through the hourly data to determine the percentage of fuel costs incurred by each entity. Staff

[38] This methodology was adopted for purposes of that case in the Commission-approved Non-Unanimous Stipulation and Agreement in Case No. ER-2009-0090.

first separates the energy supplied by each entity and assigns a rank to each energy source from least expensive to most expensive. Staff then looks at each hour and assigns the lowest cost generation available for that entity to serve its native load and tracks the cost and amount of the energy from that generator.[39]

After determining whether the native load for each division could have been met for a given hour by that division's assigned generation, the allocation method stores the MW and cost data and moves on to the next hour. If energy in excess of what was needed was generated by a source, the allocation method stores that information and moves on to the next hour. If energy is needed to meet the load requirement of an entity, a decision is made on how to economically meet this need, i.e., where to obtain the least expensive energy. This involves either taking a transfer from the other entity (excess energy generated) or taking purchased power from the energy market.

Based on application of its balancing methodology, Staff recommends annual allocation factors for fuel and purchased power costs of ** ______ ** to MPS and ** ______ ** to L&P.

Staff Expert/Witness: Erin L. Maloney

8. Capacity Contract Prices and Energy

Capacity contracts are contracts entered into between electric providers 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. GMO's capacity contracts include the Gray County

[39] In this stage, Staff does not consider whether more economical generation is available from the other division, but only examines (1) whether or not native load is met by the native generation sources, (2) how much extra energy, if any, is available from each entity, and (3) the cost of the excess energy.

Wind Contract, and the Nebraska Public Power District (NPPD) Cooper Contract, and the NPPD Gentleman Contract.

GMO's actual hourly contract transaction prices for the period of twelve months ending June 30, 2010, were obtained from the data GMO supplied to comply with 4 CSR 240-3.190 and were used by Staff to calculate each contract's average monthly prices.

Staff Expert/Witness: David W. Elliott

9. Hourly Net System Loads

Hourly net system load is the hourly electric supply necessary to meet the energy demands of both the company's customers and the company's own needs. MPS and L&P (collectively, GMO) hourly loads used in the analysis of the test year ending December 2009 were provided to Staff in GMO work papers provided with direct testimony and in response to DR No. 105. Hourly load data submitted monthly by GMO in compliance with the Commission's rule 4 CSR 240-3.190 ("3.190 data") was used to cross check the GMO data. The cross check supported L&P's data but revealed inconsistencies between the 3.190 data and the MPS data used by GMO in its work papers. In addition to submitting data requests concerning the inconsistencies, Staff discussed the inconsistencies with GMO. Based on these discussions, Staff used the data provided in response to its data request in its analysis of MPS's net system load.

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

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

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

Staff uses the process described in Weather Normalization of Electric Loads, Part A: Hourly Net System Loads [40].

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

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

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

Staff Expert/Witness: Walt Cecil

a. Normal Weather

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

i. Losses

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

GMO has different rate schedules for MPS and L&P. The rates for these schedules are based on separating GMO's investments and costs to serve each. To determine the line loss factor for MPS and L&P, Staff used the variables in the following equations for both MPS and L&P and solved for the system energy loss (line loss) of each.

System energy losses are calculated as a percentage of Net System Input (NSI). NSI is equal to the sum of retail and wholesale sales, plus energy used in operating the respective facilities (Company Use), plus system energy losses. Therefore, system energy losses for both MPS and L&P may be calculated using the following equation:

System energy losses = NSI – (Retail Sales + Wholesale Sales + Company Use).

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

Staff has calculated a system energy loss percentage for the twelve months ending December 2009 of 6.14% of NSI for MPS and 6.26% of NSI for L&P. These line loss percentages were provided to Staff expert Walt Cecil, who used them in developing the system loads for both MPS and L&P that are inputted into Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

10. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the GMO generating unit outages were normalized by averaging the nine years of actual values taken from data supplied by GMO to comply with 4 CSR 240-3.190.

Staff Expert/Witness: David W. Elliott

11. Capacity Requirements for the Territory Formerly Known as MPS

a. Capacity Requirements for This Filing

Staff has included in its case for MPS the capital costs of two 105 megawatts (MW) combustion turbines (CTs) on the six 105 MW CT South Harper site that have not been built. Staff refers to these two combustion turbines as Prudent Turbines 4 and 5. As it has in prior cases, the capital costs Staff used for these two CTs in its case are the book values they would have had if the two CTs had been built and become fully operational and used for service at the same time in 2005 when the three 105 MW CTs that are on the six CT South Harper site were built and Aquila began to use them for providing service. It is Staff's position that Aquila should have built five 105 MW CTs at the South Harper site, rather than the three it actually built, given the information that was available to GMO (then known as Aquila, Inc.) through its resource planning process at the time GMO was deciding how it was replacing the power it was getting from the Aries plant (now the Dogwood plant) through a capacity contract.

Staff first raised in testimony pre-filed in September 2003, in Case No. EF-2003-0465, its concerns regarding Aquila, Inc.'s lack of planning to replace the 500 MW of summer capacity and energy that it was then obtaining from the exempt wholesale generator Aries plant owned jointly by Aquila's subsidiary Aquila Merchant Services, Inc. and Calpine through a five-year purchased power agreement ("Aries PPA") that was to end in May 2005. At that time, Aquila had not informed Staff of how it planned to meet the capacity needs of MPS for the summer of 2005. A description of the correspondence and discussions that occurred between Staff and GMO for the next two years is described in the attached Appendix 5, Schedule LMM-1.

Appendix 5, Schedule LMM-1 also describes that Staff first presented its position that the prudent decision for Aquila was to build five 105 MW CTs at the South Harper site, not three in Case No. ER-2005-0436. Staff has not waivered from this position in any case since that Aries PPA expired. Staff maintained the same position in Aquila's following two general rate increase cases, Case No. ER-2007-0004 and Case No. ER-2009-0090 (filed as GMO).

As a part of GMO's last rate increase request, Case No. ER-2009-0090, because the legal cloud South Harper was resolved, Staff included the three 105 MW CTs built at the South

Harper site as part of GMO's rate base. However, it is still Staff's position that GMO should have built five 105 CTs at the South Harper site when it built only three. Therefore, in this case Staff is imputing both the capital and running costs of two 105 MW CTs at the South Harper site in its direct filing that GMO did not build.

Since GMO should have built five 105 MW CTs at its South Harper site to meet the customer load on its system when the Aries PPA expired, Staff is not including the capital and running costs of GMO's Crossroads four 75 MW CT power plant in Staff's direct case. A utility should locate and size a generating plant to serve its native load. The Crossroads power plant was neither located nor sized to meet MPS's native load. It was built as a merchant plant to sell energy at market value. Where the price and circumstances are right, such as distress sales, acquisition of plants built by others, including those built as merchant plants such as Crossroads, acquiring an existing power plant could be a preferred option. Staff did not include the capital and running costs of the Crossroads power plant for four reasons: (1) affiliate transaction concerns discussed in greater detail in the next section of this report; (2) historically the prices of natural gas delivered to Crossroads have been higher than the natural gas prices delivered to South Harper; (3) the cost of transmission to move the energy from Crossroads to GMO's service area when, since South Harper is in GMO's service area, there is no similar cost for South Harper; and (4) the ability of GMO to properly provide managerial oversight on a power plant located in Mississippi, several hundred miles from GMO's load center.

b. Potential Impact on Future Capacity Balance

Staff still remains concerned with GMO's resource plans. Appendix 5, Schedule LMM-2 is a capacity balance sheet for GMO with the two CTs Staff is imputing to the South Harper site. All other capacity resources and the peak forecast are the same as the preferred plan that GMO filed with the Commission in its last Chapter 22 Electric Utility Resource Planning compliance filing (Case No. EE-2009-0237). This schedule shows that ** ______________________________ ** Since GMO's last rate case, GMO has ** ______________________________ ** at the time of its last rate case, Case No. ER-2009-0090. Staff is concerned that GMO will not be able to obtain the demand-side reduction shown on Appendix 5, Schedule LMM-2 because KCPL has publically stated that it is not going forward with any additional demand-side programs and GMO's demand-side programs are tied to those of KCPL. GMO has not requested non-traditional rate-making treatment, as allowed by the Missouri Energy Efficiency Investment Act ("MEEIA"), and GMO has stated that it will not seek that non-traditional rate-making treatment allowed by the MEEIA until the Commission rules are final. While Staff sees the value in waiting until Commission rules are final, the MEEIA is the law and nowhere in the MEEIA is it required there be Commission rules before a utility can ask for non-traditional rate-making treatment. Demand-side resources, like supply-side resources, take time to implement. So this delay could mean that GMO will not have enough capacity over the next few years to meet its customers' demand for electricity. After KCPL's statement that it will not be going forward with any additional demand-side programs, GMO has not changed its resource plans to meet the anticipated additional demand for electricity through supply-side resources.

If, instead of using the capital and running costs of two additional 105 MW CTs for determining GMO's cost of service, the Commission uses the capital and running costs of the

Crossroads units (four 75 MW CTs for a combined capacity of 300 MW) GMO acquired from its unregulated affiliate Aquila Merchant, ** ____________________ . ** However, if GMO ** ____________________ ____________________ ____________________ ________ **

Staff Expert/Witness: Lena Mantle

<u>12. Allocation of Iatan 2 Capacity Between MPS and L&P</u>

Staff recommends that 100 MW of GMO's 153 MW share of Iatan 2 be allocated to L&P, including the investment and costs associated with it, and the remaining 53 MW be allocated to MPS. Staff primarily bases its position on St. Joseph Light & Power Company's ("SJLP's") resources when GMO[41] and SJLP merged. At that time SJLP had an 18% ownership of Iatan and a 100 MW base load purchased power agreement ("PPA").

GMO obtained its ownership in the Iatan Station, including the opportunity to own part of Iatan 2, when it acquired SJLP. At the time of the merger, SJLP owned 18% of Iatan. Now GMO owns 18% (153 MW) of the 850 MW Iatan 2 plant. GMO has two sets of rates. GMO's service area where L&P rates are in effect is the former SJLP service area. L&P rates are still primarily based on the same generating plant and purchased power agreements ("PPAs") SJLP used to serve its customers before GMO acquired SJLP; including SJLP's costs and investment in Iatan 1 and its PPA with Nebraska Public Power District ("NPPD PPA"). L&P's base load capacity will be reduced by 100 MW when the NPPD PPA ends on May 31, 2011.

[41] In this section of the Report "GMO" refers to KCP&L-Greater Missouri Operations Company and its predecessors Aquila, Inc. and UtiliCorp United, Inc.

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With this allocation, both L&P and MPS receive some of the Iatan 2 base load capacity. Staff realizes that economic conditions are tough and the rate impact of adding 100 MW of Iatan 2 investment and costs in L&P's revenue requirement will not be easy for many of its customers. However, in the long run, as they are with Iatan 1, L&P customers will reap the benefits of this low cost base load unit for many years to come.

Staff Considerations in Determining Its Recommendation

GMO, in 2000 when it was named UtiliCorp United, Inc., merged with SJLP. Afterward it consolidated the tariffs of the two former entities into one tariff, except that it kept separate rate schedules for the pre-merger GMO and SJLP service areas. To avoid the issue of increasing rates in the SJLP service area due to the merger and GMO's financial situation, in its application to the Commission for authority to merge, GMO committed to not changing the rates in that service area because of the merger. GMO expressed a long term goal of having one rate schedule rather than two - single tariff pricing; however, it has not yet proposed to move MPS and L&P rates to a single rate schedule for the entirety of GMO's service area.

Until this case, with the addition of Iatan 2 at a nearly $2 billion cost, GMO's capacity costs were easily identifiable to either MPS or L&P. Although MPS and L&P generation is jointly dispatched, GMO has not needed additional capacity to serve L&P customers until now. Prior to the addition of Iatan 2, GMO's capacity addition investment and costs since the merger have all been assigned to MPS. The portion of the high capital cost of the Iatan 1 scrubber that was GMO's responsibility was only included in the revenue requirement upon which rates were set for L&P customers in GMO's last rate case, Case No. ER-2009-0090 because SJLP owned 18% of Iatan 1 when GMO merged with it and the scrubber addition was an improvement to

Iatan 1. A more detailed explanation of why MPS and L&P have separate rates and their resources can be found in Appendix 5, Schedule LMM-3.

GMO has not proposed in this case to begin merging the MPS and L&P rates. GMO's proposed rates for MPS and L&P in this case would have the effect of making the difference between MPS rates and L&P rates greater. If GMO had single tariff pricing, then there would be no allocation of Iatan 2 investment and costs within GMO.

Given GMO has shown no inclination to begin to merge the MPS and L&P rates, the best way to determine how to allocate Iatan 2 investment and costs between them for ratemaking purposes would be to base the allocation on resource planning by GMO performed separately for MPS and L&P. Of course, one of the synergies of the merger of GMO and St. Joseph Light & Power Company is that GMO does not have to build separately to meet load for MPS and L&P, i.e., all the generation is jointly dispatched. Therefore, GMO has not performed resource planning separately for MPS and L&P.

In its resource planning meetings before GMO acquired ownership of a portion of Iatan 2, Staff urged GMO to build or acquire base load capacity to better balance its generation portfolio. When GMO obtained an ownership interest in Iatan 2, it was not immediately evident how GMO intended to recover its capital investment in Iatan 2, i.e., which GMO retail customers would pay for Iatan 2 – those billed under MPS rates or those billed under L&P rates, or both. GMO had been doing its resource planning on a total company basis, not separately for MPS and L&P. Until the addition of Iatan 2, it was obvious that the decisions GMO (then known as UtiliCorp) made in 2000 were driving GMO's needs for additional capacity to serve MPS customers.

Initially, GMO wanted to allocate the investment and costs of all 153 MW of GMO's share of Iatan 2 to MPS. This would have given MPS some fuel and purchased power expense stability, and diversified MPS's generation portfolio. Staff and other stakeholders voiced their concerns about allocating all of Iatan 2 to GMO. Iatan 2 was, and is, likely to be one of the last coal plants built in the Midwest for quite some time due to uncertainty regarding potential federal emissions restrictions. Absent its merger with SJLP, which owned 18% of Iatan 1, it is unlikely that GMO could have acquired any ownership of Iatan 2. In addition, L&P needed additional capacity to replace L&P's base load contract with NPPD that would end soon after Iatan 2 was planned to come on line.

When Staff expressed its concerns regarding GMO's intent to allocate all of Iatan 2 to MPS, Aquila committed to Staff that it would work with stakeholders to develop a methodology to allocate Iatan 2 between MPS and L&P.

Staff also expressed its concerns regarding the allocation of Iatan 2 to Great Plains Energy, Inc. ("GPE") when GPE requested authorization from the Commission to acquire GMO (then named Aquila). Again, GPE assured Staff that it understood Staff's concerns and committed to work with stakeholders to develop a methodology for allocating Iatan 2 between MPS and L&P. After GPE acquired GMO, GMO again assured Staff that it was working on an allocation methodology and that it would share that methodology with Staff and other stakeholders.

Despite all these assurances by GPE and GMO, which started before construction of Iatan 2 began, that GMO would work with Staff to develop an appropriate allocation of Iatan 2 investment and costs between MPS and L&P, GMO's direct testimony filing in this case is the first time that GMO has presented a proposed allocation of Iatan 2 investment and costs between MPS and L&P.

Since separate resource plans do not exist for MPS and L&P and GMO did not work with stakeholders to determine an appropriate allocation of Iatan 2 investment and costs to MPS and L&P, Staff considered several factors when determining its proposed allocation. These factors include:

1. The capacity needs of MPS and L&P
2. The ownership "rights" to Iatan 2
3. The impact on customer rates

Staff examined five different allocation scenarios in its analysis of how to allocate Iatan 2. These scenarios are:

Scenario 1: All 153 MW to L&P

Scenario 2: 100 MW to L&P and 53 MW to MPS

Scenario 3: 53 MW to L&P and 100 MW to MPS

Scenario 4: GMO's position of 41 MW to L&P and 112 MW to MPS

Scenario 5: All 153 MW to MPS

A detailed discussion of the factors Staff considered, along with the scenario Staff finds most appropriate, follows.

<u>The Capacity Needs of MPS and L&P</u>

Because separate resource plan studies are not available for MPS and L&P, Staff does not know GMO's exact needs to separately serve its MPS and L&P customers. The capacity needs of MPS and L&P that Staff has previously discussed in this Report are based on Staff's knowledge of resource planning, the generation plant characteristics and loads of MPS and L&P when GMO and SJLP merged in 2000, and GMO's current resource plans.

With these limits, if MPS were a standalone utility, it would be very beneficial for MPS to diversify its generation portfolio with base load capacity. In addition, MPS likely will need more capacity, if not in 2010, soon after. The lower fuel cost of base load capacity would also likely stabilize MPS's fuel costs. Scenario 5 above, all of Iatan 2 allocated to MPS, would be the most appropriate scenario, if the only consideration is MPS's needs as a standalone utility.

If L&P were a stand-alone utility, it would need to replace the 100 MW NPPD PPA that ends in May 2011. Since the NPPD PPA is a base load contract, it would be logical for L&P to replace it with base load capacity. It would also be logical, since L&P already has so much base load capacity, that L&P instead add lower capital cost peaking capacity rather than base load capacity. But, since the opportunity to own a portion of another base load unit in the Midwest is not likely to occur in the near future, and given that L&P could sell excess energy on the market, L&P, as it did when it invested in Iatan 1, may have chosen to add more base load. Scenarios 1, 2 and 3 are reasonable for GMO if the only consideration is L&P's needs as a stand alone utility.

<u>Ownership Rights to Iatan 2</u>

GMO obtained ownership of Iatan 1 by merging with St. Joseph Light & Power Company. If they had not merged, given GMO's poor financial condition when KCPL was looking for potential partners for Iatan 2, KCPL would not have considered GMO as a potential partner.

If ownership rights were the only factor considered for allocating Iatan 2, then all of GMO's portion of Iatan 2 would be allocated to L&P. Therefore Scenario 1 would be appropriate, if the only consideration is the source of ownership rights to Iatan 2.

Impact on Rates

The capital investment in Iatan 2, a base load plant, is very high. However the impact on revenue requirement due to capital investment should not be considered alone when determining the revenue requirement impacts of Iatan 2. Because Iatan 2 is expected to be the most efficient unit and to have the lowest running cost of all of GMO's generating resources, the revenue requirement impacts due to the reduction of fuel and purchased power costs associated with Iatan 2 should also be considered. Integral to the current methodology of allocating fuel costs to MPS and L&P is the assignment of power plants to either MPS or L&P. A history and description of the fuel allocation methodology can be found on Appendix 5, Schedule LMM-4.

The fuel cost to MPS is minimized when all of Iatan 2 is allocated to MPS. And the same is true for L&P when all of Iatan 2 is allocated to L&P. Therefore the net fuel cost impact on either MPS or L&P is the difference between the fuel cost of each scenario minus the fuel cost of the scenario where all of Iatan 2 is allocated either to MPS or to L&P. In addition, the net impact on L&P is less than GMO's capital investment and costs of Iatan 2 since L&P will no longer have to pay the NPPD PPA capacity costs that L&P have been paying since 1996. The non-fuel net cost to L&P is the difference between the revenue requirement due to the capital investment and costs of Iatan 2 and the NPPD PPA capacity costs.

To get a feel for the total revenue requirement impacts on MPS and L&P, Staff calculated the Iatan 2 revenue requirement[42] for MPS and L&P for the scenarios listed above. Staff's fuel and purchased power allocation methodology described in Appendix 5, Schedule LMM- 4 was applied to the results of Staff's fuel run model[43] for each of the five scenarios to calculate the

[42] Fixed charges and depreciation at Staff mid-point ROR of 7.98%. Does not include fuel, non-wage O&M, wage, insurance, property taxes

[43] Staff's fuel run model with Iatan 2, without Crossroads, with Prudent CTs 4 & 5, without NPPD PPA, and with December 2010 estimated fuel prices.

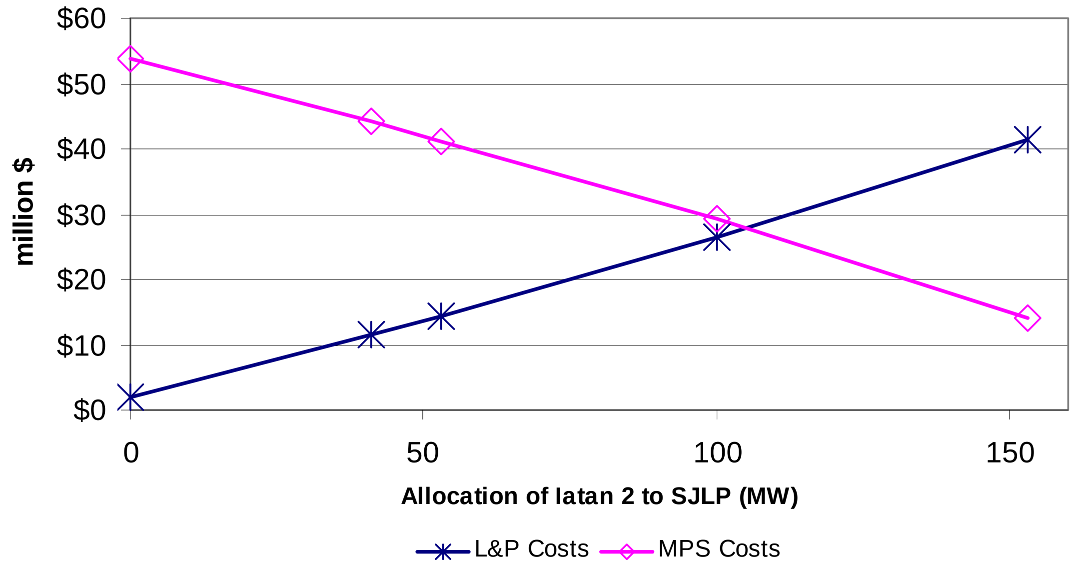
difference in the fuel costs for MPS and L&P for each of the five scenarios. From these results Staff was able to estimate the impact of Iatan 2 on fuel costs. The total impacts on MPS and L&P and the percent of current revenues for each are shown in the tables below.

MPS				
Scenario	**Capital Costs**	**Change in Fuel Costs**	**Total**	**% of Current Revenue**
1	$0	$14,115,884	$14,115,884	2.6%
2	$18,645,319	$10,532,214	$29,177,533	5.3%
3	$35,180,760	$6,079,896	$41,260,656	7.5%
4	$39,401,433	$4,764,849	$44,166,282	8.0%
5	$53,825,174	$0	$53,825,174	9.8%

L&P					
Scenario	**Capital Costs**	**Change in Fuel Costs**	**NPPD Capacity Payment**	**Total**	**% of Current Revenue**
1	$53,446,831	$0	$12,120,000	$41,326,831	31.4%
2	$34,933,389	$3,583,635	$12,120,000	$26,397,024	20.1%
3	$18,514,261	$8,035,858	$12,120,000	$14,430,119	11.0%
4	$14,322,353	$9,350,953	$12,120,000	$11,553,306	8.8%
5	$0	$14,115,810	$12,120,000	$1,995,810	1.5%

Choosing a scenario that minimizes rate impacts for MPS customers results in the maximum rate impacts for L&P customers, and when rate impacts are minimized for L&P customers they are maximized for MPS customers.

To get an idea of what allocation would minimize the costs to both MPS and L&P, Staff plotted the total cost for the 5 scenarios. This graph is shown below.



These two lines cross at approximately 100 MW, i.e., the cost to the MPS and L&P are the same at 100 MW.

Staff's position of 100 MWs for L&P will potentially cause the rate increase to L&P customers to be almost four times the rate increase to MPS customers. However, currently the bill of a typical residential customer using the Company's estimated use of 1130 kWh per summer month and 780 kWh per winter month on MPS's residential rates is approximately 19% higher than a residential customer with the same usage on L&P's residential rate. Staff's proposed allocation will not result in GMO's rates for L&P surpassing GMO's rates for MPS. However, this proposed allocation of Iatan 2 investment and costs is not outside the probable realm of what would have occurred to the rates of L&P customers if they were still in a stand-alone St. Joseph Light & Power Company, and moves GMO's L&P rates closer to those of MPS.

<u>Conclusion</u>

Taking into account their probable resource needs if MPS and L&P each were stand alone utilities, the source of GMO's ownership rights to Iatan 2, and rate impacts, it is Staff's position that 100 MW of Iatan 2 should be allocated to L&P and 53 MW should be allocated to MPS. All additions of large base load units in Missouri initially have resulted in a large increase on the utility's revenue requirement. Staff's current research shows that the initial inclusion of St. Joseph Light & Power Company's investment and costs in Iatan 1 in its revenue requirement caused its rates to increase by over 26%. When Union Electric Company's investment and costs in the Callaway Nuclear Plant were initially included in its revenue requirement, despite having a large customer base, it caused Union Electric Company's rates to increase by 45%. Further, when KCPL's investment and costs of the Wolf Creek Nuclear plant was first included in KCPL's revenue requirement, it caused KCPL's rates in Missouri to increase by 21.75%. Despite the initial large increase in rates when these base load units were first included in the utilities' revenue requirements, in the long-term they have resulted in lower rates for the customers of these utilities - lower rates which those customers are now enjoying.

Staff Expert/Witness: Lena Mantle

13. MPS Prudent Combustion Turbines

Staff is sponsoring adjustments for MPS to continue Staff's position in GMO's last three rate cases, Case Nos. ER-2005-0436, ER-2007-0004, and ER-2009-0090 as it relates to the GMO capacity issue described above by Staff witness Mantle. The adjustments Staff is proposing reflect the continuation of Staff's position that GMO should have prudently addressed its capacity needs for MPS to replace the Aires PPA when it expired on May 31, 2005. As related by Staff witness Mantle GMO chose not to replace the Aires PPA with its least cost option of building and owning five 105 MW CTs.

Staff's position is that it was imprudent of GMO not to build and own the five 105 MW CTs in 2005. Instead, GMO only built three 105 MW CTs and continued to rely on short-term purchased power capacity contracts for the remaining 210 MWs until 2008. In 2008 GMO, through an unreported affiliate transaction with its Merchant affiliate began relying on capacity located in Mississippi from another peaking facility—four 75 MW CTs at a site called Crossroads Energy Center ("Crossroads") that was built in 2002 by Aquila Merchant. GMO's approach was short-sighted and imprudent because it placed the short-term financial considerations of GMO over the long-run financial interests of GMO's customers paying MPS rates. Due to this imprudence GMO has incurred higher long-term capacity costs than it should have and Staff is making adjustments to GMO's plant in service and expenses so those higher costs are not passed on to GMO customers. The adjustment value is the difference between including the higher costs of GMO's Crossroads in rate base less the costs of adding two additional 105 MW CTs at South Harper in 2005 when it constructed and installed three 105 MC CTs.

South Harper is a natural gas-fired peaking facility currently capable of generating up to 315 MW that is located in Cass County, Missouri. As a peaking facility, South Harper typically operates during peak electricity demand periods, such as the hot summer days in June, July, August, and September; however, it may also operate in non-peak periods to support the power system grid during maintenance on other units, or during generation shortages and emergencies, or other circumstances where it is the lowest cost plant to dispatch. Major construction of South Harper was completed in June and July 2005. The site was designed for six 105 MW CTs, but GMO has only constructed three 105 MW CTs. Staff refers to these three CTs are South Harper CTs 1, 2 and 3. Because GMO should have built five 105 MW CTs in 2005 rather than three, Staff is imputing to MPS the costs GMO would have incurred if GMO had built and installed five 105 MW CTs at South Harper in 2005. Therefore, in determining the revenue requirement for MPS Staff has, in addition to including the costs of the South Harper CTs 1, 2 and 3, included the costs of two additional 105 MW CTs--South Harper prudent CTs 4 and 5.

Because GMO is meeting its capacity needs with the CTs at Crossroads and not the South Harper prudent CTs 4 and 5 Staff has also made adjustments to its Accounting Schedules to remove all incremental costs related to the Crossroads facility that are included in GMO's test year books and records for MPS—costs such as costs to operate Crossroads, including depreciation expense, transmission charges to transfer the electricity from Mississippi to Missouri, maintenance charges including labor, operations and maintenance expenses, and property taxes. In their place, Staff has included what it believes to be a reasonable approximation of the costs that GMO would incur had it built and installed the South Harper prudent CTs 4 and 5 at South Harper in 2005.

To estimate the costs GMO would now be incurring for five 105 MW CTs at South Harper, Staff has factored up GMO's 2009 test year costs of the three CTs it built and installed at the South Harper in 2005 on a pro rata basis to be representative of five 105 MW CTs. These costs include plant and reserve, depreciation expense, maintenance charges including labor, operations and maintenance expenses, deferred taxes and natural gas pipeline reservation charges. When the plant costs for South Harper Prudent CTs 4 and 5 are included in the rate base for MPS they generate depreciation expense and an overall rate of return on the net rate base amount.

Staff calculated a pro rata amount of depreciation reserve and deferred income taxes associated with South Harper Prudent CTs 4 and 5 and made and adjustment to reflect this amount in the revenue requirement for MPS. To calculate June 30, 2010 depreciation reserve balances for South Harper Prudent CTs 4 and 5 Staff took the June 30, 2010 reserve to plant balance ratio for South Harper CTs 1, 2 and 3 and multiplied the June 30, 2010 plant balances it calculated for South Harper Prudent CTs 4 and 5 by this ratio. To calculate the level of South Harper Prudent CTs 4 and 5 accumulated deferred income taxes to include in the rate base for MPS, Staff calculated the cumulative depreciation timing differences of accelerated tax depreciation and book depreciation through June 2010 and multiplied this cumulative timing difference by GMO's approximately 38.4 percent effective tax rate.

The plant and reserve amounts for South Harper Prudent CTs 4 and 5 that Staff included in its June 2010 revenue requirement for MPS are shown below.

Acct	Prudent CTs 4 &5	June 2010	Dep Reserve	Net Plant
353	Transmission Plant	$2,211,353	191,282	2,020,071
340	Land	0	0	0
341	Structures	$5,142,029	386,084	4,755,945
342	Fuel Holders	$2,102,714	334,934	1,767,780
343	Prime Movers	$36,255,099	8,061,969	28,193,130
344	Generators	$9,217,285	1,727,638	7,489,647
345	Accessory Equip	$9,447,889	1,195,102	8,252,787
346	Misc Pwr Plt Equip	$66,435	8,462	57,973
		$64,442,804	11,905,471	52,537,333

The total plant costs for South Harper Prudent CTs 4 and 5 included in this case were based on Staff's estimate of the costs to build South Harper prudent CTs 4 and 5 in 2005. In Case No. ER-2005-0436, Staff used documents containing GMO's actual costs data for the purchase of the three 105 MW CTs GMO built and installed at South Harper in 2005 as the basis for Staff's calculation of the costs of South Harper Prudent CTs 4 and 5. This amount is ** ___________ **, less accumulated depreciation. The chart below shows all of the plant components included in the total gross plant amount for South Harper Prudent CTs 4 and 5 included in Staff's Surrebuttal filing in Case No. ER-2005-0436:

NP

	MPS # 4	MPS # 5	Transmission	Common	Total
Plant	$18,700,000	$18,700,000	$2,100,000	$6,436,658	$45,936,658
AFUDC	$1,308,353	$1,308,353	$111,353		$2,728,059
Construction Costs	$7,600,000	$7,600,000	$0		$15,200,000
Total Plant in Service	$27,608,353	$27,608,353	$2,211,353	$6,436,658	$63,864,717

The $18.7 million estimated cost of the South Harper Prudent CTs 4 and 5 and the $2.1 million estimated cost of the transmission upgrades are addressed by Staff witness Featherstone. Added to the estimated cost of the CTs is an allowance for funds used during construction (AFUDC). AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during the construction period. AFUDC is capitalized as a part of the cost of utility plant.

As the basis for its AFUDC estimate, Staff used a workpaper GMO provided that reflects the actual costs of construction of the three South Harper CTs. The cost sheet, titled "South Harper Peaking Facility Weekly Cash Flow Updated September 21st" (South Harper Construction Cost workpaper) reflects the construction costs of South Harper Units 1, 2 and 3 through September 21, 2005. The actual AFUDC costs charged to South Harper Unit #1 was $1.6 million.

This amount applied to capitalized direct charges of $23 million, results in an AFUDC rate of approximately 7%. Staff's $18.7 million cost per Ct multiplied by 7% results in the capitalized AFUDC cost of $1.3 million per CT.

Staff used the same method to determine the AFUDC rate for transmission plant. The South Harper Construction Cost workpaper for the Belton South to Peculiar transmission project shows AFUDC loadings of $187,751 based on direct charges of $3.5 million, for an AFUDC rate of 5.3%. Applying this rate to the transmission plant cost of $2.1 million, results in a capitalized AFUDC cost of $111,353.

Therefore, Staff added $7.6 million of construction costs for each CT. The CT construction costs are based on GMO's actual costs to build the three CTs at South Harper. The highest cost GMO incurred to construct any of the three South Harper CTs was $7.5 million. This was the cost of construction for South Harper CT 3.

The South Harper Construction Cost workpaper shows total costs to construct common plant at South Harper for three CTs, or 315 MW, to be $19.3 million. Staff used a ratio of 210 MW/ 315 MW and multiplied this 67% times the $19.3 million to arrive at a value of $12.9 million. Staff then applied a fifty percentage (50%) downward adjustment factor to this result. The downward adjustment was made to recognize the likelihood that building two additional CTs will increase the need for additional common plant, but the additional common plant needed by adding two CTs will be significantly less than in initial common plant built for the three CTs at South Harper.

Staff’s position in Case No. ER-2005-0436, Aquila’s 2005 rate case was that while the cost of constructing two additional CTs was higher in the short-term, because the rate of return is applied to a declining net plant amount over time, the cost of ownership will decline over time and it will be cheaper in the long run to own the CTs than continue to use short-term PPAs. For example, by including South Harper Prudent CTs 4 and 5 in rate base in Aquila’s 2007 rate case, No. ER-2007-0004 Staff's revenue requirement recommendation increased by $12 million. This $12 million included by Staff was higher by $4.6 million than the cost for this capacity proposed by GMO in that case—$7.3 million.

Staff’s position that although the cost of constructing two additional CTs was higher in the short term than relying on PPAs, because plant-related costs decline over time, it will be cheaper in the long run to build them began to bear fruit in GMO’s 2009 rate case, No. ER-2009-0090. In that rate case the cost included in Staff's revenue requirement for its 310 MW of capacity (two 105 MW CTs and a 100 MW PPA) was approximately $12 million. The costs GMO included in its case for 310 MW from Crossroads was approximately $23 million, for a revenue requirement difference of about $11 million. This $11 million represents part of the cost of the imprudent capacity planning decisions of GMO that Great Plains Energy inherited when it purchased Aquila, Inc. GPE's management has deal with this cost, but it should not be allowed to pass this cost on to GMO's ratepayers. That is still Staff's recommendation to the Commission.

In this case, the cost difference between including Crossroads in rate base for MPS instead of South Harper Prudent CTs 4 and 5 is $15 million. A snapshot of this revenue requirement differential is shown below. This analysis uses the grossed up rate of return GMO proposes in this case, GMO's and Staff's respective proposed depreciation rates, and assumes no material impact of the differences in property taxes, maintenance and other related expenses between Crossroads and South Harper Prudent CTs 4 and 5.

	Crossroads	CT 3 & 4
Net Plant	$107	$52.5
Deferred Taxes	($6)	($17)
Net Rate Base	$101	$35.5
GMO-Grossed Up Rate of Return	12.5%	12.5%
Return on Rate Base	$12.6	$4.4
Depreciation	$5.5	$2.3
Transmission-Crossroads	$5.4	$0
Gas Reservation	$0.5	$2.4
Total Revenue Requirement	$24	$9
Difference		($15)

The reason for the significant difference is deferred taxes between Crossroads and Prudent CTs 4 and 5 is that GMO refuses to include the cumulative deferred taxes that have accrued on Crossroads since that plant has been operating. GMO's position is that it's Missouri regulated customers are not entitled to the deferred taxes that accrued to Crossroads while it was a Merchant Plant for Aquila. When KCPL and GMO transferred Crossroads from non-regulated Merchant Plant to Regulated Plant, Aquila recognized a significant inter-company gain which it retained for non-regulated operations and eliminated the accrued deferred taxes that should have transferred with the ownership of the Crossroads plant.

Staff Expert: Charles R. Hyneman

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

1. Payroll Costs

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

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

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

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

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

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

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

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

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

After allocating between expense and construction based on the expense factor, which in File No. ER-2010-0355 is a three-year average, the adjustment for payroll was distributed by individual FERC account based upon the actual distribution for each of those accounts for 12-months ending June 30, 2010, the update period used in this case. Adjustments

L&P: E-4.3, 5.1, 14.1, 15.2, 17.1, 18.2, 24.3, 25.3, 26.3, 27.3, 28.3, 38.1, 41.1, 42.1, 46.2, 47.2, 48.2, 60.1, 61.2, 67.1, 68.1, 69.1, 74.1, 80.1, 81.1, 82.1, 89.1, 90.1, 91.1, 92.1, 93.1, 94.1, 95.1, 96.1, 97.1, 102.1, 103.1, 104.1, 105.1, 106.1, 107.1, 108.1, 109.1, 110.1, 115.1, 116.1, 117.5, 119.1, 122.1, 123.1, 124.2, 125.1, 128.1, 129.1, 131.1, 135.2, 137.1, 141.2, 142.6, 147.4, 148.1, 150.1, 152.2, 153.1, 155.1, 158.2

MPS: E-4.2, 5.1, 10.1, 11.1, 12.1, 13.1, 17.1, 18.1, 19.3, 20.3, 21.3, 30.1, 31.1, 35.1, 36.1, 39.2, 40.1, 41.2, 42.2, 46.1, 51.2, 57.2, 62.1, 63.1, 64.1, 65.1, 66.1, 76.1, 77.1, 78.1, 79.1, 80.1, 85.1, 86.1, 87.1, 88.1, 89.1, 90.1, 91.1, 92.1, 93.1, 97.1, 98.1, 99.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 109.1, 110.1, 111.1, 113.1, 116.1, 117.1, 118.2, 119.1, 122.1, 123.1, 125.1, 129.1, 130.2, 131.1, 135.1, 136.4, 137.2, 139.1, 143.1, 144.1, 145.2, 146.1, 148.1, 151.1,

Staff Expert/Witness: Bret G. Prenger

2. Payroll Taxes

Staff annualized payroll taxes by applying current payroll tax rates to each employee's annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and partner billings, Staff applied an aggregate tax rate based on the annualized payroll taxes for base payroll. The payroll taxes follow the same allocation process used to allocate base payroll. Adjustments E-174.3 (L&P) and E-167.1 (MPS) to the Income Statement reflect the annualized payroll taxes based on payroll costs as of June 30, 2010.

Staff Expert/Witness: Bret G. Prenger

3. Payroll Related Benefits

Payroll related benefits general include 401k expenses, medical costs, and other employee benefits. Staff calculated annualized 401k expenses based upon the test year percentage match for GMO applied to its share of total annualized payroll. In addition, Staff removed the joint partner share of GMO 401k expenses from the annual level similar to the annualized payroll adjustment.

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

Staff calculated other employee benefits, located in Account 926, based upon the twelve months ending June 30, 2010. Other benefits include items such as Educational Assistance and Recreational Activities. Adjustments E-142.7 (L&P) and E-136.6 (MPS) to the Income Statement reflect the calculated payroll related benefits based on payroll costs as of June 30, 2010.

Staff Expert/Witness: Bret G. Prenger

4. True-up of Payroll Costs

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

Staff Expert/Witness: Bret G. Prenger

5. Iatan 2 Ownership Allocation

Staff is proposing an adjustment in Case ER-2010-0356 to include and allocate between MPS and L&P Staff's determination of GMO's ownership of Iatan 2. GMO owns 18% of both Iatan 1 and Iatan 2. Staff has included in its direct filing payroll related strictly to Iatan 1 and Iatan 2. Staff initially distributed that payroll amount equally to Iatan 1 and to Iatan 2. Then, Staff multiplied each by 18% based on GMO's ownership share. Staff assigned the resulting payroll amount for Iatan 1 to L&P. Staff allocated the resulting payroll amount for Iatan 2 to MPS and L&P based on Staff's proposal that 100MW of Iatan 2 be allocated to L&P and 53 MW be allocated to MPS. This is a reallocation of payroll that Staff had originally allocated using the payroll allocators for allocating payroll between —KCPL, MPS and L&P, 9.38% for L&P and 22.55% for MPS. However; the correct allocators for allocating Iatan 2 between L&P and MPS are: 65.40% (L&P) and 34.60% (MPS). The difference between the Iatan 2 payroll amounts Staff obtained from its original allocation and the amounts it obtained from using the correct allocators multiplied by the transfer to expense, or O&M percentage (75.39%) represents Staff's proposed adjustments. Adjustments E-4.4 for MPS and E-4.4 for L&P, respectively are Staff reallocated Iatan 2 payroll adjustments.

Staff Expert/Witness: Bret G. Prenger

<u>6. FAS 87 and FAS 88 Pension Costs</u>

Financial Accounting Standard (FAS) 87 states that the accrual accounting method should be used to calculate pension cost for financial reporting purposes. However, for MPS and L&P, both Staff and the Company recommend continuation of the settlement agreement originally approved in Case No. ER-2004-0034 and continued in Case Nos. ER-2005-0436, ER-2007-0004 and ER-2009-0090.

The settlement agreement provides that the minimum contributions required under the Employee Retirement Income Security Act (ERISA) will be used in determining MPS's and L&P's pension cost for ratemaking purposes. ERISA was established by federal statute in 1974 and is intended to ensure the funding of defined benefit pension plans.

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.

In GMO's last general electric rate case, Case No. ER-2009-0090, the parties entered into a settlement agreement to use the provisions that were established in GMO's previous rate cases, Case No. ER-2007-0004, 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 and ER-2009-0090.

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 Staff has reflected in this current case, Case No. ER-2010-0356, are based on continuation of the agreements reached in the above-referenced stipulation and agreements.

Staff's rate base calculation includes a Missouri jurisdictional balance of $0 and $10,253,303 for MPS and L&P prepaid pension asset unrecovered balance, as of June 30, 2010, respectively. MPS's prepaid pension asset was fully recovered on October 31, 2009; therefore, MPS's balance was set to $0. The L&P unrecovered balance will be updated through December 31, 2010, in the true-up portion of this case.

As of June 30, 2010, MPS and L&P have respectively collected $696,938 and $2,022,355, less in rates than the actual contributions made to the pension fund. This regulatory asset is reflected as an increase to MPS's and L&P's rate base and amortized as an increase to pension cost over 5 years. Adjustments E-136.1 and E-142.1, in Staff Accounting Schedule 10, respectively adjust the 2010 test year pension cost for MPS and L&P to reflect a normalized level of contributions to the pension fund. A full year of amortization is included in the cost of service for the L&P prepaid pension asset, therefore there is no adjustment necessary for this case.

Additionally, KCPL and GMO made a determination to combine all of its pensions and OPEBs into one plan under its parent company, Great Plains Energy. The Company and its actuary, Towers Watson, proposes to switch the accounting method for calculating pension costs in this rate case from minimum ERISA (contributions) to FAS 87 (accrual). The reasoning for this change is that many of their employees now perform services for both KCPL and GMO during any given year. This means it is impossible to isolate specific pension benefits earned while performing services for KCPL. For example, if an employee splits time between KCPL and another entity based on a ratio of 75%/25% one year and 40%/60% the next, there is no way to track the separate benefits being earned and the underlying asset values supporting these benefits for KCPL or GMO on a prospective basis. As a result, the existing regulatory assets (from minimum ERISA) should be amortized until the balances reach $0. In addition, the Company proposes a different pension tracking mechanism be implemented subsequent to the effective date of new rates in this proceeding, based on pension accrual accounting (FAS 87).

As a result of the Company combining its pension plans under the FAS 87 accounting method for this case, Staff reflected the Company's pension costs under FAS 87 in Staff's income statement in this case consistent with the ratemaking treatment applied to other regulated utilities within Missouri. The rate base amounts and cost of service adjustments Staff has reflected in this current case, Case No. ER-2010-0356, are based on continuation of the agreements reached in the stipulation and agreements in previous rate cases based upon ERISA. However, a different pension tracking mechanism will need to be implemented subsequent to the effective date of new rates in this proceeding, based on pension accrual accounting. MPS & L&P's ongoing level of FAS 87 cost recognized in rates in this case is $7,945,506 and $672,833, respectively.

Staff Expert/Witness: Paul R. Harrison

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

Other Post-Employment Benefit Costs (OPEBs) are those costs incurred by the Company to provide certain benefits to retirees. These benefits include medical, dental, vision, 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 OPEB costs for MPS and L&P. Section 386.315, RSMo. (2000) requires that the Commission:

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

Section 386.315.2 essentially 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. Section 386.315 also mandates that all of the funds be used for employee or retiree benefits.

MPS and L&P are funding their annual FAS 106 costs. Staff adjustments E-136.3 and E-142.3 adjust the MPS and L&P test year 2009 FAS 106 OPEBs costs to reflect the more current FAS 106 calculation as of June 30, 2010.

Staff's adjustment annualizes OPEBs expense as calculated under FAS 106, for MPS and L&P employees. The amount of OPEB expense included in Staff's cost of service calculation reflects MPS' and L&P's current liability to provide retiree medical payments to its current employees as well as to its retired employees.

Staff Expert/Witness: Paul R. Harrison

<u>8. OPEB Tracker</u>

Based upon an analysis of the three previous years of the MPS and L&P's OPEB expense Staff determined that the OPEB expense fluctuated significantly from year to year. By using a tracker, the cost of the OPEB expense will be recovered through rates for both the rate payer and

Company in future rate cases. At the present time Empire District Electric Company, Empire District Gas Company and AmerenUE all have an OPEB tracker.

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

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

Staff Expert/Witness: Paul R. Harrison

9. Supplemental Executive Retirement Plan (SERP) Expense

Included in Staff's revenue requirement recommendation for GMO is the test-year amount of recurring (non lump-sum) SERP payments made by the Company to its former executive and other highly-compensated employees as appropriately adjusted and allocated by Staff.

A SERP is an additional executive pension compensation program that provides benefits to highly-compensated employees over and above the benefits provided under the "all-employee" regular pension plan. A SERP exists only because the Internal Revenue Code ("IRC") does not permit a tax deduction for pension expense above a certain dollar amount. Companies create a SERP to allow its highly-compensated employees to receive pension benefits over and above the amount that the IRC allows as a reasonable business deduction.

Staff adjusted MPS' test year per book amount of SERP expense and included MPS-GMO's 2009 income statement to a level Staff considers appropriate. Staff's proposed level of SERP expense for MPS-GMO is $89,321 which is lower than MPS-GMO's test year per book amount of $95,246 net SERP expense.

MPS capitalizes a portion of its SERP expense to capital projects, such as regulatory assets and construction work-in-progress. Staff does not believe that SERP payments should be capitalized in a manner similar to normal pension expense. The SERP payments are made to former employees who provide no current or future value to the utility's operations or the construction of capital assets. Therefore, all of the payments, to the extent that they are reasonable and prudently incurred, should be charged to expense.

Staff's SERP adjustment for MPS is based on the actual recurring payments made as shown in GMO's response to Staff Data Request No. 301. In that data request response, GMO listed for MPS each former executive who received a SERP payment in 2009 and the amount of the SERP payment made. However, it does not appear that GMO made an allocation of the SERP payments to MPS that was representative of the allocation of expense these former Aquila, Inc. corporate employees charged to Missouri regulated operations (MPS and L&P). For example, in prior rate cases Aquila Inc. allocated only approximately 20 percent of the payroll and other costs of the Chief Administrative Officer to MPS and approximately 8 percent to L&P, for a total amount of 28 percent to Missouri regulated operations. In its adjustment in this rate case, GMO appears to be allocating 100 percent of the SERP payments to Missouri regulated operations. In its adjustment, Staff attempted to allocate the appropriate amount of SERP expense for each former Aquila executive based on service provided these employees provided to Missouri regulated operations.

Staff also made an adjustment to the amount of annual recurring SERP payments made to two former Aquila executives from in excess of $70,000 per year to approximately $50,000 per year. SERP in the amount of $50,000 is the amount paid to a former Aquila Senior Vice-President with over 22 years of service to Aquila, and is the amount Staff established as a ceiling of reasonableness. Staff believes any recurring SERP payment to former Aquila executives above this amount is excessive and should not be included in cost of service.

Finally, in Aquila's past rate cases, Staff took issue with the fact that a significant level of Aquila's SERP expense was based on compensation received as bonus payments and incentive compensation that was not included in cost of service. To prevent SERP expense based on non-regulated compensation from being included in its adjustment, Staff reduced each former employee's SERP payment by 20 percent prior to allocation to Missouri regulated operations. The 20 percent is an estimate of the amount of annual recurring SERP expense that is based on non-regulated compensation.

Staff did not allocate any of the SERP expense for the former Aquila executives to L&P. On October 19, 1999, Aquila Inc. (then named UtiliCorp United Inc.) and St. Joseph Light & Power Company (SJLP) filed a Joint Application seeking authority to merge SJLP with Aquila. The Commission issued a Report and Order on December 14, 2000, approving the merger. Since all or nearly all of the former Aquila executives provided most of their service to Aquila prior to the merger, Staff determined it would not be appropriate to charge L&P customers an expense that was not related to any economic benefit provided to them.

Staff has made an adjustment to remove the test year per book amount of SERP for L&P and therefore has not included in GMO's revenue requirement any SERP payments made to the former SJLP executives. When Aquila merged with SJLP in 2000, it also purchased the assets in SJLP's funded SERP. It has been Staff's position in prior rate cases, which it continues in this case, that the assets in this SERP fund 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, Inc. purchased the assets in the SERP fund when it merged with SJLP, there was no longer any future SERP expense to be recognized for the former SJLP executives. It is and has been Staff's position that all SERP payments to the former SJLP executives should be made from the SERP fund that was acquired by Aquila, Inc. and subsequently acquired by Great Plains Energy in its acquisition of GMO in 2008.

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, Staff treats SERP costs somewhat differently from normal employee pension costs. 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 excessive, are reasonably provided for, and are able to be quantified under the known and measurable standard. Staff's proposed level $89,321 for MPS's annual recurring SERP payments meets this test.

Staff Expert/Witness: Charles R. Hyneman

10. Short-Term Incentive Compensation

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

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

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

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

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

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

** ** Remaining in the cost of service are the projected payouts at the target level for salaries as of June 30, 2010 as updated by the Company. Staff has proposed to remove the amounts the Company did not include in the cost of service in its direct filing in prior rate cases. In those cases, the Commission adopted Staff's position. Staff would

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have proposed a similar adjustment to incentive compensation if the full amount were included in the cost of service.

While Staff agrees with the adjustments GMO has made in this case, Staff continues to evaluate the Company's philosophy on compensation and benefits. Incentive compensation is but one factor in KCPL's total pay and benefits package, in addition to deferred compensation, pension, and health and welfare benefits.

MPS: E-4.3, 12.2, 36.2, 62.2, 85.2, 93.2, 110.3, 117.6, 129.4

L&P: E-4.3, 66.3, 89.3, 97.3, 115.3, 123.5, 135.4

Staff Expert/Witness: Bret G. Prenger

11. Long-Term Incentive Compensation

The Long Term Incentive Compensation Plan ("the plan") for the 2009-2011 calendar years was based on two goals, each weighted at 50%. The two goals were FFO to Total Adjusted Debt and Earnings Per Share ("EPS"). The purpose of the plan is to encourage executive and other key KCPL employees to acquire a vested interest in the growth of and performance of Great Plains Energy. Eligible employees include executives and other employees of GPE and KCPL, as approved by the Compensation and Development Committee of the Board of Directors. The awards generally given are 50% restricted stock, with the number of shares determined at the date of grant based upon the GPE stock price. The other 50% of the awards will be performance shares with that number granted to be determined by the fair market value at date of grant. Time-based restricted awards and performance shares will be payable in GPE common stock. As part of GMO Adjustment CS-11, the Company removed all costs associated with long-term officer incentives stating "the costs are ordinary and reasonable business expenses; however, we do not believe such costs should be borne by ratepayers." Staff

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agrees with the adjustment and has removed all associated costs from Staff's revenue requirement calculation.

Adjustments: L&P: E-135.3 MPS: E-129.3

Staff Expert/Witness: Bret G. Prenger

C. Maintenance Normalization Adjustments

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

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

Staff analyzed maintenance costs from 2001 through 2009, by functional area for production, transmission, distribution, and general plant by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff's detailed position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report. The maintenance analysis was done only on non-wage maintenance and operating costs.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by Staff, was to compare functional averages which included using a two (2) year average through a seven (7) year average to determine if there were fluctuations with each functional area. Each of the costs by year and averages for maintenance were also compared to the 2009 Test Year. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs. Staff's results are presented in the following table;

Results of Staff's Non-Labor Maintenance Analysis		
	GMO-MPS	**GMO-L&P**
Steam Production Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Other Production Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Transmission Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Distribution Maintenance	3-Year Average (2007-2009)	2009 Test Year

The adjustments for MPS shown on Staff Accounting Schedule 10 are: Production Maintenance E-17.2, E-18.2, E-19.2, E-20.2, E-21.2, E-39.1, E-40.1, E-41.1 and E-42.1. Transmission Maintenance E-72.1, E-76.2, E-77.2, E-78.2, E-79.2 and E-80.1. Distribution Maintenance E-97.2, E-98.2, E-99.2, E-100.2, E-101.2, E-102.2, E-103.2, E-104.2 and E-105.3. The adjustments for L&P shown on Staff Accounting Schedule 10 are: Production Maintenance

E-24.2, E-25.2, E-26.2, E-27.2, E-28.2, E-45.1, E-46.1, E-47.1 and E-48.1. Transmission Maintenance E-78.1, E-79.2, E-80.2, E-81.2, E-82.2, and E-83.1

Staff Expert/Witness: Karen Lyons

1. Iatan 2 O&M Expenses

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

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

Staff Expert/Witness: Karen Lyons

D. Depreciation - Clearing

During the test year, the Company included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to remove the depreciation amount booked to the clearing account. MPS Adjustment E-148.2, L&P Adjustment E-155.2.

Staff Expert/Witness: Karen Lyons

E. SJLP Merger Transition Costs

On October 19, 1999, Aquila, Inc. (then named UtiliCorp United Inc.) and St. Joseph Light & Power Company (SJLP) filed a Joint Application seeking authority to merge SJLP with Aquila. The Commission issued a Report and Order on December 14, 2000 with which it authorized the merger.

GMO's current electric rates for MPS and L&P reflect the continuation of a 10-year recovery of transition costs Aquila incurred during the process of integrating SJLP's electric operations into Aquila's Missouri regulated electric operations. The Commission approved recovery of transition costs associated with the merger of the electric operations of SJLP and Aquila to be recovered over ten years when it approved the *Nonunanimous Stipulation and Agreement*, in Case No. ER-2005-0436, in particular paragraph 12 of that agreement. In the associated *Staff's Suggestions in Support of the Nonunanimous Stipulation and Agreement*, at paragraph 18, Staff informed the Commission that Staff and Aquila agreed to an annual amortization of $314,886 for MPS and $106,187 for L&P. The Commission approved this agreement in its *Order Approving Stipulation* issued on February 23, 2006.

Because GMO records this amortization below-the line for accounting purposes, an adjustment is necessary to bring the cost above the line for ratemaking purposes. Staff made adjustments to the MPS and L&P income statements to reflect a *pro rata* 10-year amortization of these transition costs.

Staff Expert: Charles R. Hyneman

1. Leases

Lease costs are those costs incurred by the Company in leasing its corporate headquarters. Staff examined these costs for test year 2009 and updated them through

June 30, 2010. KCPL moved its corporate headquarters to One Kansas City Place, 1200 Main Street, Kansas City, Missouri during the fourth quarter of 2009.

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

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

Staff adjusted the Company's test year amount for lease rent during the substantial period of time KCPL was paying the final months of its lease at its previous headquarters and paying leasing payments on its new corporate headquarters while it was being renovated. The leasehold adjustment results in a decrease in Total Company lease expense that is identified as Adjustment

E-154.1 (L&P) and E-141.1 (MPS). An additional adjustment is being made to reflect the decrease for the abatement period—this is identified as Adjustment E-154.2 (L&P) and E-141.3.

Adjustments E-154.1, E-154.2, E-158.1, 136.1 (L&P)

Adjustments: E-141.1, E-141.3, E-130.1, and 151.2 (MPS)

Staff Expert/Witness: Bret G. Prenger

2. Property Tax Expense

Each year KCP&L-Greater Missouri Operations (GMO or Company) is billed by each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property GMO owns exclusively on January 1st of that calendar year. The property taxes assessed on January 1st of each year are not due to the taxing authorities until December 31st of that same year. The test year used in this case is the 12-month period ending December 31, 2009, updated through June 30, 2010. Since the update period in this case is June 30, 2010, Staff determined the annualized property taxes based on the property GMO had in-service on January 1, 2010. Staff applied a property tax ratio based on actual 2009 property tax payments to January 1, 2009 plant. This ratio of property taxes when applied to the January 1, 2010 plant provides the amount of property taxes expected to be paid for 2010. Since the actual 2010 property taxes owed by the Company have not been paid as of the update period, June 30, 2010, Staff plans on updating GMO's property taxes for the true-up which will be through December 31, 2010. Because the update in this case is June 30, 2010 property tax expenses for 2010 were annualized as of the January 1, 2010 date. This calculation is an estimate of the total 2010 property tax expense. Both Staff and the Company typically accomplished this by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year. For the current rate case, Staff obtained from

GMO the total amount of taxable property owned on January 1, 2010, and then applied to it the tax rate assessed to the Company in 2009. The property tax rate assessed in 2009 is calculated by dividing the total amount of property tax paid by the Company by the total cost of the taxable property owned on January 1, 2009. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2010. Staff believes that the property tax expense arrived in this manner is the best available information, since it relies on the actual January 1, 2010 balance of GMO's property, and uses the most recent, known tax rate (2009), without attempting to estimate any change in the rate of taxation for 2010 that is not known as of the update period June 30, 2010. The property taxes will be trued-up during that phase of the case. During the true-up Staff will examined the actual amount paid for property taxes for 2010 as that amount will be known at the end of the year.

Staff adjusted test year property tax expense in order to include in rates the annualized level of 2010 property taxes. Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in prior cases, most recently in KCPL'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 made an adjustment to include an annualized amount for property taxes. Adjustment for MPS E-170.1 and L&P E-175.1 reflects the annualized levels.

Staff Expert/Witness: Karen Lyons

3. Bad Debt Expense

Bad debt expense is the portion of retail revenues MPS and L&P are unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. If MPS and L&P are subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense.

Staff calculated the annualized bad debt expense by examining the billed revenues for the twelve months period ending December 31, 2009, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending June 30, 2010. From this information a bad debt ratio was derived, which was then applied to Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with MPS's and L&P's position on how bad debt write-offs are accounted.

The Company asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue. These are adjustments E-112.1 for MPS and E-118.1 for L&P.

Staff Expert/Witness: Amanda C McMellen

4. Advertising Expense

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

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

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

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

Following the Company/Staff meetings, Staff has come to the conclusion to make adjustments to Accounts 908.000 and 909.000, as well as to pick up the Company adjustments to Accounts 913.000 and 930.100. The 908 Account represents the Connections program, and while certain aspects of the program are beneficial, Staff believes a significant portion of the program represents costs pertaining to CEP/Energy Efficiency and DSM, which in prior cases are costs Staff and Company have agreed to capitalize. Staff chose to expense 50% of the costs and then capitalize the other 50% of the costs dealing with this program. This is referring to charging the costs to a plant account as compared to charging them strictly to expenses. Account 909 deals with general advertising costs in which after review, Staff found several costs also associated with CEP and Energy Efficiency. Based on the handling of these costs in case ER 2009-0089, Staff believes they should also be capitalized. Finally, Staff chose to include the two Company adjustments for accounts 913 and 930.1 that simply reflect the change between test year and known and measureable.

Adjustments L&P E-123.2, E-124.1, E-130.1, E-152.1

Adjustments MPS: E-117.2, E-118.1, E124.1, 145.1

Staff Expert/Witness: Bret G. Prenger

5. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations, that GMO charged to its' utility accounts during the test year. Consistent with Staff policy for many years, Staff included all dues payments made by GMO to each area's Chamber of Commerce, and removed the other dues, as Staff believes that these additional amounts are not necessary in the provision of utility service. This adjustment was made to Account 930.2. In addition, Staff removed costs Staff considers to be personal or of no benefit to the ratepayer and thus not appropriate for inclusion in a utility's cost of service. Staff also removed costs associated with Dollar-Aide contributions, including an adjustment that the Company chose to apply to their case.

Adjustments L&P: E-117.1 and E-153.2

Adjustments MPS: E-111.3 and E-146.2

Staff Expert/Witness: Bret G. Prenger

6. Debit/Credit Card Acceptance Program

In September 2009, MPS and L&P implemented a Credit/Debit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. The program is offered by MPS and L&P in an agreement with Western Union through its SpeedPay service, which acts as a third party facilitator for the processing of payments to MPS and L&P. When payment is made by a customer through the credit or debit card system, MPS and L&P will receive payment from Western Union. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and or by registering on MPS's and L&P's website. Payment through the website offers two options one time payments or what the Company terms the, "recurring card payment option," which is available through registration on its website. The cost for providing this service is absorbed by MPS and L&P and later built into rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in September 2009, customer participation has been gradually increasing. Participation is projected to increase into the future as more customers become aware of the program. As customer participation increases, the per unit transaction cost to MPS and L&P for providing the debit/credit payment service will decline.

Staff has included in its cost of service an annualized amount associated with the credit and debit card program based upon the total card level and per unit transaction cost as of the six months ending June 30, 2010 multiplied by two, which represents an ongoing level of costs. The cost was then allocated to MPS and L&P based on customer levels at June 30, 2010. These adjustments are represented in Staff's Accounting Schedules as E-111.4 for MPS and E-117.3 for L&P.

Staff Expert/Witness: Amanda C McMellen

7. Accounts Receivables 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, GMO was 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 MPS and L&P 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 MPS and L&P ratepayers. The loss of the sale of the accounts receivables resulted directly from the problems that Aquila faced in its non-regulated ventures.

In 2009, GMO began negotiations with account securitization facilities to establish an account receivable contract. GMO was unable to establish an accounts receivable contract because it did not have at least three years of account receivable data as a standalone company. GMO provided the following explanation as to why it was unable to establish an account receivable program.

> "KCP&L GMO ("GMO") pursued the establishment of a $55 million accounts receivable securitization facility in 2009 through the Bank of Tokyo-Mitsubishi-UFJ ("BTM"). However, BTM notified GMO in July 2009 that its credit committee would not approve funding such a facility because there was not at least three years of standalone GMO accounts receivable data available post-acquisition by Great Plains Energy. Following BTM's rejection of the transaction, GMO approached JP Morgan to gauge their interest in such a facility and received the same feedback."

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 72% of its account receivables, which include the account receivables of GMO and L&P. When calculating an appropriate amount for GMO and L&P, Staff used the receivable balance from December 31, 2009. Adjustment E-116.2 (L&P) and E-110.3 (MPS).

Staff Expert/Witness: Bret G. Prenger

8. Outsourced Meter Reading

GMO contracts with a third party to perform meter reading services for MPS. The third party service provider is Corix Utilities (Corix). Corix bills the company based on the number of meter reads it performs each month. Staff made an adjustment to the 2009 test year to reflect an annualized amount. Adjustment E-109.2

Staff Expert/Witness: Karen Lyons

9. Miscellaneous Test Year Adjustments

In its direct filing, GMO proposed Adjustment CS-11 which includes several miscellaneous adjustments. Among the miscellaneous adjustments were the test-year executive expense reports, and other items that are non-recurring or that should be booked below the line. Additionally, KCPL identified the effects of an error in the Massachusetts formula. The Massachusetts formula is used to allocate expenses between operating units and the holding company, namely KCPL, GMO, and GPE, respectively. Staff has included the effects of KCPL's change in the Massachusetts formula with the exclusion of labor. Staff's payroll adjustment sufficiently captures the correct allocation of costs between KCPL, GMO, and GPE. Adjustment Numbers E-12.3, E-14.1, E-57.4, E-62.3, E-87.2, E-93.3, E-98.3, E-109.4, E-116.2, E-129.5, E-130.4, E-132.1, E-133.1, E-140.5, E-141.1, E-151.3, E-157.1, E-165.1, and E-174.1 to the MPS Income Statement and Adjustment Numbers E-61.2, E-66.2, E-91.2, E-97.2, E-103.2, E-115.4, E-122.2, E-135.5, E-136.3, E-138.1, E-139.1, E-142.8, E-147.5, E-148.2, E-153.4, E-158.3, E-166.1, E-172.1, and E-180.1 to the L&P Income Statement account for the above miscellaneous expenses in the cost of service.

Staff Expert/Witness: Keith A. Majors

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

In Staff's "Construction Audit and Prudence Review" of the Iatan Construction Project dated November 3, 2010, Staff captured the additional Allowance for Funds used During Construction ("AFUDC") due to the Iatan Unit 1 turbine start-up failure GMO owns an 18% share of Iatan 1.

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

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

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

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

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

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

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

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

> ** ____
> ____
> ____
> ____
> ____

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____
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____
_______________________ **

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

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

Staff Expert/Witness: Keith A. Majors

11. Demand-Side Management Cost Recovery

KCP&L Greater Missouri Operations Company ("GMO") had limited demand-side programs prior to its acquisition by Great Plains Energy. However, since its acquisition by Great Plains Energy, demand-side programs consistent with the demand-side programs of

Kansas City Power & Light Company ("KCPL") have been successfully implemented in both MPS & L&P. On September 15, 2010, Staff provided to the Commission a Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives (File No. AO-2011-0035). Attached to this Staff Report as Appendix 6, Schedule JAR-1 are pages from the Status Report, which highlight the GMO Advisory Group[44] process and the challenges and successes to date of GMO's demand-side programs.

GMO's overall spending levels for demand-side programs have approximated the spending goal of one percent of annual revenues to implement cost-effective demand-side programs ordered and approved in stipulation and agreements in GMO's 2007 general rate case (Case No. ER-2007-0004) and in GMO's 2007 Chapter 22 Electric Utility Resource Planning compliance filing (Case No. EO-2007-0298). Further, as reported by GMO for the September 15, 2010 Status Report filing, through June 30, 2010 the total budget for all GMO demand-side programs is $12,036,668 and the actual total expenditures through this period are $10,564,587, or 12% less than budget. Such "under spending" is normal during the early years of demand-side programs' implementation, as a utility's customers become familiar with newly offered demand-side programs and decide to take actions necessary to participate in demand-side programs.

The energy and capacity impacts and the overall delivery processes of the programs are still being evaluated, measured and verified by a third-party contractor of GMO and will be provided to the GMO Advisory Group members along with copies of completed program evaluation reports. The results of future evaluation reports are not expected to impact this case

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

(see the **DSM Costs** section and the **Demand-Side Management Prudence** section of this Staff Report)

It is Staff's understanding that GMO is not accepting new applications for its large customer MPower demand-response program due to a reduction in the GMO load forecast, which GMO attributes to the current economic recession. It is Staff's understanding that GMO intends to continue offering services of its other energy efficiency, demand response and affordability programs to meet customer demand for these programs. Staff and other parties continue to be engaged with GMO as part of the GMO Advisory Group process to provide advice on the GMO's demand-side programs and as part of the stakeholder group for GMO's Chapter 22 Electric Utility Resource Planning process.

The ordered and approved Stipulation and Agreement as to Certain Issues in Aquila, Inc.'s, n/k/a GMO's, 2007 general rate case (File No. ER-2007-0004) includes the following:

> 11. **Demand Side Management ("DSM") Program Costs.** The signatories agree that for ratemaking purposes Aquila will defer the costs of DSM programs in Account 186 and calculate allowance for funds used during construction (AFUDC) annually. DSM programs are defined as demand response and energy efficiency programs. The prudently-incurred cost included in the Account 186 balance will be amortized over a ten (10) year period. When new rates go into effect reflecting amortization recovery as a result of future general rate proceedings, the prudently-incurred costs included in the Account 186 balance will be added to rate base, Aquila will stop accruing AFUDC on the amount included in rate base, and Aquila will begin amortizing the balance. Additional DSM program costs incurred after the effective date of a final Report and Order in the initial general rate proceeding following Case No. ER-2007-0004 will be treated in the same manner, but will be deferred in a different sub-account by vintage.

The direct testimony of Company witness Tim M. Rush in this general rate proceeding includes a request for continuation of the current accounting treatment of GMO's DSM programs' costs and amortization over ten years of these costs. Staff is in support of this request (see the **DSM Costs** section of this Staff Report).

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

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

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

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery

> infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.

Subsections 393.1075.3 and 4, RSMo. Supp. 2009.

While Staff does not view GMO's existing demand-side programs presently to be demand-side programs proposed pursuant to section 393.1075.4 RSMo. Supp. 2009 and since GMO did not ask for different treatment of demand-side cost under MEEIA, current accounting treatment of GMO's demand-side programs' costs and the amortization over ten years of these costs as discussed in this section and in the **DSM Costs** section of this Staff Report should be continued until the Commission has rules in effect to implement MEEIA.

Staff Expert: John A. Rogers

12. Demand-Side Management Prudence

The Demand-Side Management (DSM) Account 182-440 contains costs that have been incurred for thirteen (13) DSM programs[45] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and (2) DSM market research costs. At this time, Staff has no recommended disallowances to the levels of costs charged to GMO's DSM Account.

As approved in stipulation and agreements and ordered by the Commission in Case Nos. ER-2007-0004 and EO-2007-0298, the GMO Advisory Group provides suggestions and advice to the Company on DSM program selection and other issues with a funding goal of one percent of annual revenues to implement cost-effective energy efficiency programs by 2010. Combined meetings of the GMO Advisory Group and the Kansas City Power & Light Company (KCPL) Customer Programs Advisory Group (CPAG) include Staff, Office of the Public Counsel, Department of Natural Resources and other interested parties. Based on Staff's participation in the Advisory Group meetings and Staff's review of the costs in Account 182-440, Staff discovered no evidence of imprudence regarding the level of costs charged to the DSM programs.

Staff Expert/Witness: Hojong Kang

13. DSM Costs

Staff has included the unamortized June 30, 2010 DSM costs for MPS and L&P in rate base. These DSM deferrals are being amortized over ten (10) years consistent with the treatment afforded these costs in prior rate cases.

Staff Expert: Charles R. Hyneman / Hojong Kang

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

14. Low Income Programs

a. Economic Relief Pilot Program

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

Staff Expert/Witness: Carol Gay Fred

i. Recommendation

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

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

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

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

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

- Acquire an independent third party evaluator for the program to track all aspects of the program for weaknesses, strengths and improvement opportunities.

- Work more extensively with Salvation Army to ensure capacity enrollment of ERPP.

- Improve on education and providing awareness of ERPP with other Energy Assistance Agencies of the availability of ERPP, i.e., United Services Community Action Agency, 211, St. Vincent de Paul, etc.

- Provide SA field staff availability to AgencyLink, the web based interface that allows registered social service agencies access to restricted and highly limited view of customer information in order to assess account status and only the information required to make a determination to qualify customers for ERPP and other agency payments.

- Continue to conduct as many as feasible Connections campaign Energy Resource Fairs on an annual basis.

Staff Expert/Witness: Carol Gay Fred

ii. Qualifying Criteria

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

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

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

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

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

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

Staff Expert/Witness: Carol Gay Fred

iii. Credits

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

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

Staff Expert/Witness: Carol Gay Fred

iv. Arrearages

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

Staff Expert/Witness: Carol Gay Fred

v. Billing Periods

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

Staff Expert/Witness: Carol Gay Fred

vi. Education

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

Staff Expert/Witness: Carol Gay Fred

vii. Program Administration

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

Staff Expert/Witness: Carol Gay Fred

b. Low-income Weatherization

Staff recommends that GMO continue to provide annual funding of $150,000 for low-income weatherization, as currently allocated between the weatherization agencies. Staff also recommends that GMO change its distribution method for the weatherization funds from monthly direct reimbursement to the Weatherization Agencies to an annual deposit of the funds to a The Missouri State Environmental Improvement and Energy Resources Authority (EIERA) account.

There are specific programs designed to help low-income customers with energy conservation. Low-income consumers often live in housing that is energy inefficient with substandard insulation and other deficiencies. These customers would benefit from building shell energy conservation measures such as weatherization or more energy-efficient appliances.

The Low Income Weatherization Assistance Program ("Weatherization Program") is administered by the Missouri Department of Natural Resources ("MDNR") using federal, state, and utility funding. The Weatherization Program is administered locally by Community Action Agencies or other local agencies ("Weatherization Agencies"). In the GMO service area, the Weatherization Program is administered by the Kansas City Housing and Community Development Department, the Missouri Valley Community Action Agency, the Community Services Inc., the West Central Missouri Community Action Agency and the Green Hills Community Action Agency.

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

According to an August 31, 2010, *Customer Program Expenditures* spreadsheet furnished to the *GMO Demand-Side Management Advisory Group* (DSMAG), attached as Appendix 7, Schedule HEW - 1, the weatherization agencies have only used ** ____ ** of the 2007 through 2010 budgeted funds for weatherization. This under-utilization of funds is primarily because of the agencies' focus on using the ARRA funding and restrictions on ARRA funds being combined with utility funds. At the end of the ARRA period the Weatherization Agencies anticipate using any surplus utility funds to maintain their level of weatherization activity.

The Missouri State Environmental Improvement and Energy Resources Authority ("EIERA") was established to manage and disburse federal and other weatherization funds for MDNR to the Weatherization Agencies according to MDNR guidelines. Currently four other Missouri jurisdictional utilities utilize the EIERA to manage their weatherization funds. The

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funds at the EIERA are invested to earn a return until they are distributed so the value of the funds is enhanced.

Staff recommends that the unutilized low-income weatherization funds be placed in an account with EIERA. In addition, in order have some additional GMO funds for weatherization when the ARRA funds are no longer available, Staff recommends that GMO continue to provide annual funding of $150,000 for low-income weatherization, as currently allocated between the weatherization agencies. Staff also recommends that GMO change its distribution method for the weatherization funds from monthly direct reimbursement to the Weatherization Agencies to an annual deposit of the funds to an EIERA account.

Staff Expert/Witness: Henry E. Warren

15. Insurance Expense

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

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

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess fiduciary
- Workman's Compensation
- Excess Workman's Compensation
- Property
- Labor Management Trust Fiduciary
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated to MPS & L&P. The MPS adjustments E-133.1 and E-134.4 and L&P adjustments E-138.1 and E-139.4 reflects the annualized levels for GMO's portion of the insurance costs.

Staff Expert/Witness: Karen Lyons

16. Injuries and Damages

Injuries and damages relate to insurance claims that are not covered by insurance policies. Injuries and damages usually consist of claims associated with general liability, workman's compensation, and auto liability. Staff analyzed five years of data and determined a three-year average, including the period of 2007 through 2009, using the actual cash payments to normalize the Company's costs associated with injuries and damages. The actual cash payments are those paid to individuals who had an injury and claim. As a result of these injuries, MPS and L&P made cash settlements. A three year average was used based on the data received from the Company. The MPS adjustment E-134.3 and L&P adjustment E-139.3 reflects a normalized level of costs for injuries and damages.

Staff Expert/Witness: Karen Lyons

17. Rate Case Expense

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

Staff usually treats rate case expense as a normalized expense necessary to provide utility service. This treatment involves determining the cost to process a rate case on a normalized level and reflecting that cost in the cost of service over the period of time between rate cases.

Staff requested invoices to support the amount of rate case expense charged to GMO in Data Request No. 154 in File No. ER-2010-0356. Staff received a list of the invoices with the amounts charged to rate case expense but did not receive any copies of invoices. Staff has issued additional discovery to obtain copies of the invoices GMO has identified as rate case expense.

In Staff's Direct filing in File No. ER-2010-0355, Staff proposed to transfer the costs charged to rate case expense that would more appropriately be charged to Iatan Unit 1 or 2. Staff expects to apply this same treatment to GMO rate case expenses. However, Staff in this case has no invoices to support any level of rate case expense in its direct filing. Staff will include all prudent and reasonable costs incurred and paid through the true-up of the current rate case, File No. ER-2010-0356, separated between costs more appropriately charged to rate case expense and those that should be charged to the Iatan Construction Projects.

Staff did include an amortization of the depreciation study over 5 years as included in rate case expense in Case No. ER-2009-0090.

Staff Adjustment E-140.4 reflects a 5 year amortization of the depreciation study in Case No. ER-2009-0090 for GMO. Staff Adjustments E-140.1, E-140.2, and E-140.3 remove the test year amortizations of rate case expenses from the 2005, 2007, and 2009 rate cases for MPS.

Staff Adjustments E-147.1, E-147.2, and E-147.3 remove the test year amortizations of rate case expenses from the 2005, 2007, and 2009 rate cases for L&P.

Staff Expert/Witness: Keith A. Majors

18. Public Service Assessment Fee/FERC Assessment Fee

The Public Service Commission assessment ("PSC Assessment") is an amount billed to each regulated utility operating under the jurisdiction of the Commission. The PSC Assessment is calculation based upon an allocation of the Commission's operating costs for regulating those utilities. GMO's PSC Assessment was annualized using the latest assessment available for the current fiscal year ("FY-2011") on information obtained from the Commission's records. The updated PSC Assessment was compared to the PSC Assessment amount included in GMO's test year to form the basis for the adjustment in Staff's revenue requirement. Staff also updated the Company Federal Regulatory Energy Commission ("FERC") Assessment paid to represent 12 months ending June 30, 2010.

Adjustments MPS: E-138.1 and E-137.1

Adjustments L&P: E-145.1 and E-146.1

Staff Expert/Witness: Bret G. Prenger

19. Transmission Expenses and Revenues Tracker

Staff has completed its review of GMO's transmission expenses and recommends the Commission authorize the Company to use two transmission expense and revenue trackers, one each for MPS and L&P. Additionally, Staff recommends GMO be required to file transmission project cost estimate information in a detailed manner and as the cost estimate of any given transmission project changes, as further described below.

The Company's historic transmission expenses are provided on Schedule TMR2010-4 of Company witness Tim M. Rush for both L&P and MPS. Schedule TMR2010-4 also includes the Company's estimate of its 12-month ending December 31, 2010 transmission expenses for both L&P and MPS that it included in its filing that initiated this case. That estimate of transmission expenses includes estimated transmission expenses for July through December 2010 and three adjustments described in the pre-filed Direct Testimony of Company witness John P. Weisensee from line 10 on page 30 to line 17 on page 31 (Adjustment CS-45) and from line 20 on page 41 to line 20 on page 43 (Adjustments CS-85 and CS-86). Staff has summarized those Company adjustments as follows:

- Adjustment CS-45: Annualized expected transmission costs in FERC account 565 based on: 1) expected increased transmission expenses primarily due to increased off-system sales made possible by Iatan Unit 2, and 2) projected costs related to SPP base plan upgrades to meet the mandatory North American Electric Reliability Corporation and SPP reliability standards, which call for one-third of each base plan project to be shared by all SPP members and the remaining two-thirds of the project cost to be allocated among the members that directly benefit from the project.

- Adjustment CS-85: Annualized Missouri regulatory assessments and FERC Schedule 12 fees based on assessment levels projected to be in effect in December 2010. Under this new procedure, FERC will begin to base its assessment on all load under SPP rates including retail load served by member companies and will bill SPP for the assessment. SPP will then pass a share of this cost through to all point-to-point and network service customers it serves.

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

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

Transmission Expenses [46]

($000)						
Year	2005	2006	2007	2008	2009	Est. 2010
MPS	$12,177	$22,674	$19,909	$22,344	$14,210	$17,228
L&P	$4,174	$4,902	$4,936	$5,416	$3,459	$1,409

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

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

[46] Including FERC Account Numbers 561400, 561800, 565000, 565020, 565021, 565027, 565030, 575700 and 928003. Note that Staff has proposed a different transmission tracker amount.

allocated to the Company. For example, the Company will be allocated approximately 4% of all transmission planned in the SPP footprint above 300 kilo-Volt (kV).

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

The full transfer of control of GMO's transmission system to participate in all functions of the Southwest Power Pool (SPP) regional transmission organization was finalized on June 18, 2009. On this date, the Federal Energy Regulatory Commission's (FERC) order accepting the "Agreement for the Provision of Transmission Service to Missouri Bundled Retail Load" was effective (retroactive to April 15, 2009), allowing the Company to exercise the authority granted to it by the Missouri Public Service Commission (Commission) in Case No. EO-2009-0179.

While GMO may have less control over expenses assigned to it by SPP than other expenses it incurs, Staff expects and encourages GMO to work within the SPP stakeholder process to advocate for transmission improvements that benefit GMO stockholders and GMO ratepayers, and to advocate for a proper allocation of transmission expenses. Staff also expects that GMO's representatives advocate in GMO's and its customer's best interest if that interest is different from its affiliate Kansas City Power & Light Company ("KCPL"). Staff notes that GMO's voice on the Members Committee of SPP is that of the representative of its affiliate KCPL, Michael L. Deggendorf, KCPL's Senior Vice President-Delivery.

In those situations where GMO has direct control over the transmission expenses it incurs, Staff recommends the Commission require GMO to file with the Commission the information shown in Appendix 8, Schedule DIB - 1, and provide the same information that is supplied to SPP, when GMO proposes a transmission project at a voltage greater than 100 kV, and that GMO be required to update that filing within seven days of when the project cost estimate is changed each time the project cost estimate changes by more than 10% from the last cost estimate GMO filed with the Commission. In addition, Staff recommends the Commission order the Company to file quarterly updates of the costs incurred and progress made towards completion of all transmission projects.

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

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

Worksheet "A-1 Revenue Credits" from the GMO's FERC Formula Rate Spreadsheet[47], updated as of 9-28-10, is attached as Appendix 8, Schedule DIB-2. The relevant account names and totals have been highlighted. These totals are for GMO (both L&P and MPS).

In order to divide the amount of the revenue credits between L&P and MPS, Staff proposes using the proportion of the Zonal "Annual Transmission Revenue Requirement" ("ATRR") that L&P and MPS had before GMO's FERC Formula Rate Filing. The Zonal ATRRs are shown on Appendix 8, Schedule DIB – 3, on page DIB-3-2.

The calculation of the proportions is shown on Appendix 8, Schedule DIB-4, along with the amounts of (1) FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission); and (2) FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity" to assign to L&P and MPS.

For the amounts updated 9-28-10, FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) and the "Net 456.1 Account Activity" are as follows:

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

Revenue Description	"Net 456.1 Account Activity"	FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission)
Staff Adjustment	Staff Adjustment 1	Staff Adjustment 2
L&P	$1,615,534	$80,336
MPS	$3,389,963	$168,573
GMO (L&P + MPS)	$5,005,497	$248,909

In Staff Report in File No. ER-2010-0355 regarding Staff's recommendation for the creation of a transmission expense and revenue tracker, Staff inadvertently used the revenue credits for KCPL for both its Missouri and Kansas jurisdictions. Staff will file an updated corrected version of its transmission tracker recommendation with the correct revenue credit amount for KCPL's Missouri jurisdiction.

Appendix 8, Schedule DIB-5 lists the differences between the transmission tracker proposed by GMO in its direct testimony and the transmission expense and revenue tracker Staff proposes. The proposed amount of Staff's transmission expense and revenue tracker is ($286,822) for L&P and $13,669,875 for MPS. The amount of FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity", is listed as Staff Adjustment 1. The amount of FERC Account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) is listed as Staff Adjustment 2.

Staff recommends that the transmission expense and credit amounts included in GMO's revenue requirements for setting rates for MPS and L&P in this rate proceeding be based on the true-up amount for the 12-months ending December 31, 2010 for (1) the expenses in the accounts listed on Company witness Tim M. Rush's Schedule TMR2010-4; and (2) the revenues in FERC Account 454.0001 (to the extent derived from transmission) and FERC account 456.1

that would be listed in the FERC Formula Filing as "New 456.1 Account Activity", as relevant to L&P and MPS .

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

Staff Expert/Witness: Daniel I. Beck

20. Smart Grid Demonstration Project

Staff is not aware of any advanced metering infrastructure (AMI) or Smart Grid applications in the GMO service territory.

Staff Expert/Witness: Randy S. Gross

IX. Depreciation

A. Recommendation

Staff recommends that the Commission order GMO to:

1. Use the depreciation rates described in Appendix 9, Schedules AR-MPS-1 for MPS, AR-L&P-1 for L&P, and AR-ECORP-1 for ECORP.

2. Record amortizations as shown in Appendix 9, Schedules AR-MPS-1 and AR-L&P-1 against plant accumulated depreciation reserve accounts to correct for

over or under accrued depreciation reserves. Staff does not recommend additional amortization of ECORP depreciation reserve at the time of this direct filing.

3. Record all plant cost of removal and salvage by FERC account, date, and location unit code in a permanent continuous record, including cost of removal and salvage for production units previously removed from service. Include in this record a differentiation between interim and final retirements and net salvage.

Staff's recommendation results in GMO's total annual depreciation expense of approximately $71,400,000, based on approximate depreciation expenses of $49,000,000 for MPS, $17,700,000 for L&P, and $4,700,000 for ECORP, and a reduction in excess accumulated depreciation reserves of approximately $5,600,000 total GMO annually, based on $3,000,000 for MPS and $2,600,000 for L&P.[48],[49] Total GMO accumulated depreciation reserve is estimated to have accrued $166,000,000 more than the appropriate reserve balance, $92,000,000 for MPS and $74,000,000 for L&P, as shown in Appendix 9, Schedules AR-MPS-2 and AR-L&P-2.

Staff's recommended depreciation rates shown in Appendix 9, Schedules AR-MPS-1, and AR-L&P-1 for MPS and L&P are based on the following:

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

2. General plant accounts 391, 393, 394, 395, 397, and 398[53] have been left at the current ordered rates for MPS and L&P, pending identification by KCPL of retirements associated with recent office consolidations and relocations.

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[48] The amortization results in a depreciation expense comparable to the use of remaining life rates. The depreciation amortizations shown on Schedules AR-MPS-1 and AR-L&P-1 are calculated as the difference in annual accruals obtained when using remaining life versus whole life depreciation rates for each plant account. This results in a fixed amortization using December. 31, 2008 plant and reserve balances as the basis for determining over or under accrued reserves. Iatan additions in 2010 for L&P do not result or require modification to these amortizations.

[49] **Remaining life**: Straight line depreciation over the composite remaining life of an account with corrections for existing accumulated reserves imbalances.

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

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

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

3. Assignments of depreciation reserve amortization to correct for over or under accrued accumulated depreciation reserves.

Staff's recommended depreciation rates shown in Appendix 9, Schedules AR-ECORP-1 are based on retaining the current ordered rates from Case No. ER-2005-0436 pending identification by the Company of retirements associated with recent office consolidations and relocations.

B. Regulatory Depreciation

Staff's recommended rates for MPS, ECORP, and L&P are based on past retirement history, with influence from retirement histories of similar utility companies and future plant operation expectations. Staff's objective in recommending rates is to match the rate of money collection from ratepayers with the consumption of utility plant using a straight line estimate of the life time cost of the plant utilized to provide the service.[54] Staff's depreciation rates are

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[53] **General plant accounts 391, 393, 394, 395, 397, and 398**: General office electronic, computer, communication, laboratory, and miscellaneous equipment

[54] The book keeping associated with regulatory depreciation expense is to:
a) Allocate and record the money collected from ratepayers for depreciation purposes to specific plant accounts,
b) Account for the consumption of the invested capital as plant equipment is retired from service,
c) Account for the cost of removal, salvage value received, and any third party payments such as insurance proceeds,
d) Provide a continuous and consistent method of recording of the above listed costs as a historical record for use in future depreciation analysis.

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

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

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

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

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

designed to account for consumption of original cost of plant, the expected cost to remove and dispose of plant at the end of its life, and the expected salvage value received at disposal.

Basic Formulas for Depreciation of Living Accounts:

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

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

Average Service Life (ASL) is the average number of years the dollars in the account are expected to remain in service. ASL is equal to the area under a survivor curve.[55] When working with living accounts, the survivor curve is not truncated, as it is expected that additional property will be placed into the account to replace property that has been retired.

Net Salvage = gross salvage - cost of removal

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

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

C. Depreciation Definitions

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

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

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

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

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

Net Salvage: Salvage value minus the cost of removal.

Remaining Life: Straight line depreciation over the composite remaining life of an account with corrections for existing accumulated reserves imbalances.

Whole Life: Straight line depreciation over the whole composite life of an account without any correction for existing accumulated reserve imbalances.

D. Staff's Analysis

Staff performed four depreciation analyses, (Case A, B, C and D) for MPS and L&P in developing its depreciation recommendation for each. The methods and components of each are discussed below, and a summary of the results of each is presented in Appendix 9, Schedules AR-MPS-3, and AR-L&P-3 as well as the Commission's currently-ordered rates for each (Case No. ER-2005-0436). Staff's use of multiple analyses allows for an apples-to-apples examination of the effects of several of the more significant variables in the field of depreciation.

Staff Case A (Included in Appendix 9, Schedules AR-MPS-3 and AR-L&P-3)

Staff's recommends the Commission order GMO to adopt for MPS and L&P the depreciation rates derived in the study labeled Case A for each account. Staff addresses two issues related to accumulated depreciation reserves and depreciation expense with this recommendation:

1. Imbalances in depreciation reserves that have built up over time,[56]
2. Discrepancies in some General plant accounts that may have resulted in erroneous depreciation study results.
3. The large increase in depreciation expense due to the addition of Iatan 2 to plant in service for L&P is not addressed in these depreciation recommendations.

[56] This is in addition to the reserves held for future cost of removal.

Staff's recommended depreciation expense compared with the Company's request for each division is as follows:

Company Division	Staff Proposal	Company Proposal
MPS	$49,057,851	$57,502,543
L&P[57]	$17,719,265	$19,501,888
ECORP	$4,700,530	$7,137,256

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

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

2. General plant accounts 391, 393, 394, 395, 397, and 398[58] have been left at the current ordered rates, pending identification by the Company of retirements associated with recent office consolidations and relocations and clarification on the accuracy of historical retirement data. For ECORP, account 390 (Structures and Improvements) was added to the list of accounts in question.

3. A depreciation amortization for all over or under accrued accounts was calculated and recommended. The amortization amounts were set at a fixed amount representing over or under accrual as of Dec. 31, 2008, amortized over the calculated remaining life for each account.

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

Staff Case B

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

1. Treatment of all Steam and Other production, Transmission, and Distribution accounts as living accounts, with mass property analysis and whole life depreciation rates. No correction for over or under accrued depreciation reserves.

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[57] These comparisons use plant balances as of Dec. 31 2008 with a modification to L&P to include an estimate of Iatan additions for plant placed in service in 2010.

[58] **General plant accounts 391, 393, 394, 395, 397, and 398**: General office electronic, computer, communication, laboratory, and miscellaneous equipment

Staff Case C

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

Staff Case C differs from GMO's request in the following respects:

1. The removal of terminal net salvage from the life span analysis for the Steam Production accounts,

2. For purposes of calculating the depreciation rates associated with the Company's Steam production accounts, Staff made modest adjustments of retirement dates proposed by the Company by increasing the life span for Iatan 2 from 50 to 60 years and adding three months to all retirement dates,[59]

3. Staff used the Mass Property method for combustion turbine analysis versus the Company proposal that used Life Span.

With these adjustments the annual depreciation expense presented in Case C by Staff for MPS and L&P is approximately $6,500,000 less for MPS and $2,000,000 less for L&P than requested by GMO. Staff does not recommend Case C, but does recommend that if the

[59] The Company proposed dates may be found in Case No. ER-2010-0356 Spanos Direct testimony Schedule JJS2010-1 at page II-27 for MPS and Schedule JJS2010-2 at page II-27 for L&P., Staff increased the assigned retirement dates by three months to revise retirement dates from June (peak load month) to Sept for each planned retirement year.

Commission adopts GMO's requested life span method of analysis for certain accounts that the Commission order the following:

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

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

3. The depreciation analysis for combustion turbines use a mass property method for estimating depreciation rates.

For Case C, Staff used the following methods and assumptions

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

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

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

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

Staff Case D

While Staff recommends the Commission authorize GMO's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case D" depreciation rates. Staff "Case D" used a negative 12% terminal net salvage for the Life Span analysis of the Steam production accounts as a comparison with Staff "Case C" which used 0% terminal net salvage. Otherwise Staff Case D is identical to Staff Case C. The negative 12% terminal net salvage is consistent with the observed history of cost of removal for KCPL, MPS and L&P, see discussion below. For MPS and L&P the increase in depreciation expense for the negative 12% net salvage is shown in Appendix 9, Schedule AR-MPS-3 and AR-L&P-3, as approximately $500,000 and $1,000,000 respectively.

E. Treatment of Steam Production Plant Accounts

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

For electric plant equipment such as transmission or distribution systems, and power generation fleets, the Mass Property model is appropriate since all vintages are assumed to have the same average service life. With these types of accounts, it is assumed that all retirements will be recorded and retired property is expected to be replaced by comparable property, with or without improvements in technology. Treatment as a living account assumes the account as a whole will continue to live indefinitely[60]. If a specific termination date where all property of all

[60] The FERC and Commission rules prescribe accounts in a Uniform System of Accounts. The USOA prescribes that assets are accounted for by function. The FERC and Commission definition of DEPRECIATION states "...from causes which are **known** to be in current operation..." not implied, thought, believed, conjectured, assumed, etc. The Commission has usually prescribed depreciation rates only by the main USOA functional accounts. It is Staffs opinion that the great majority of electricity produced in Missouri in the foreseeable future will continue to be generated by the spinning of a shaft (rotor & armature), powered by flowing water, steam, or combustion gases. Replacement of these facilities with wind turbines, solar, fuel cells, or capturing solar winds is not within the current depreciable lives of these facilities. Consequently the USOA functional accounts remain relevant as living accounts. While it is known that generation units will retire, it is also known from the Company's history that these facilities typically evolve piecemeal by replacement with similar functional units.

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

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

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

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

1. Mass Property Type Survivor Curves

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

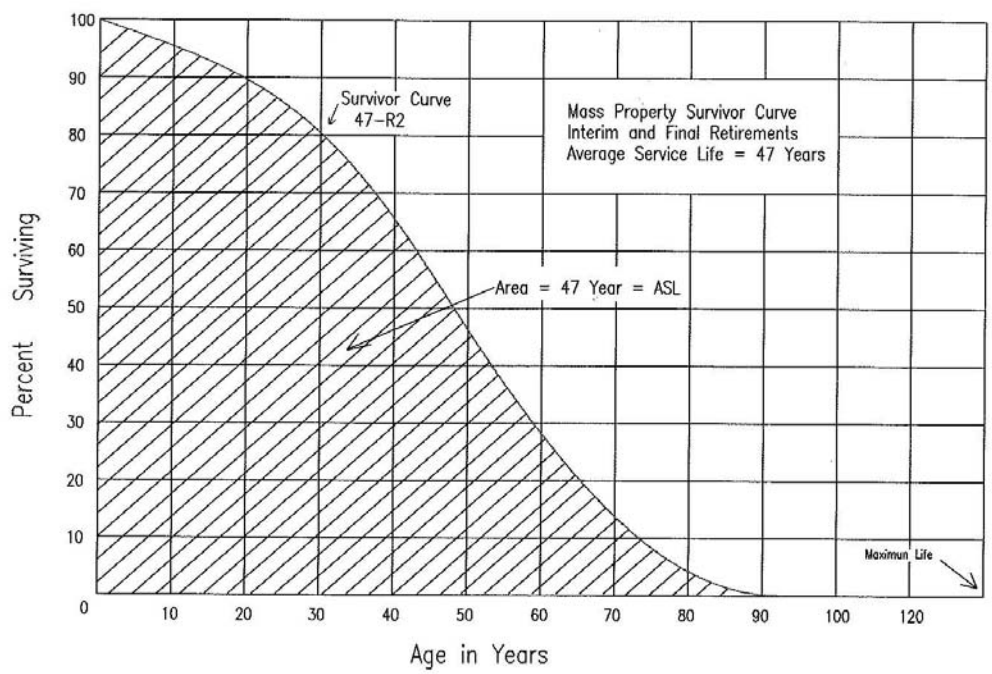

Figure 1 Mass Property Type Survivor Curve

The Companies have provided sufficient final retirement history including terminal retirements to allow reasonable estimation of average service lives for the Company's steam production accounts.[61]

Staff does not generally have a means of accurately predicting a retirement date and conducting life span analysis on each production unit, unless there is a specific issue with that unit. Staff is not aware of any specific issues for MPS or L&P where Staff has reason to assign a specific retirement date. The Commission and Commission Staff have assigned depreciation rates in the past and continue to recommend the assignment of depreciation rates to a fleet of similar production units.[62]

2. Life Span Type Survivor Curve

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

[61] Final retirement descriptions provided by the Companies were used to construct representative final retirement entries in the Company-provided historical data file.
[62] Typically all production units have main accounts (ie 311, 314, 322, 344) ordered at the same depreciation rate.

the life span for Figure 2 was specifically chosen at 60 years to produce a 47 year average service life.[63]

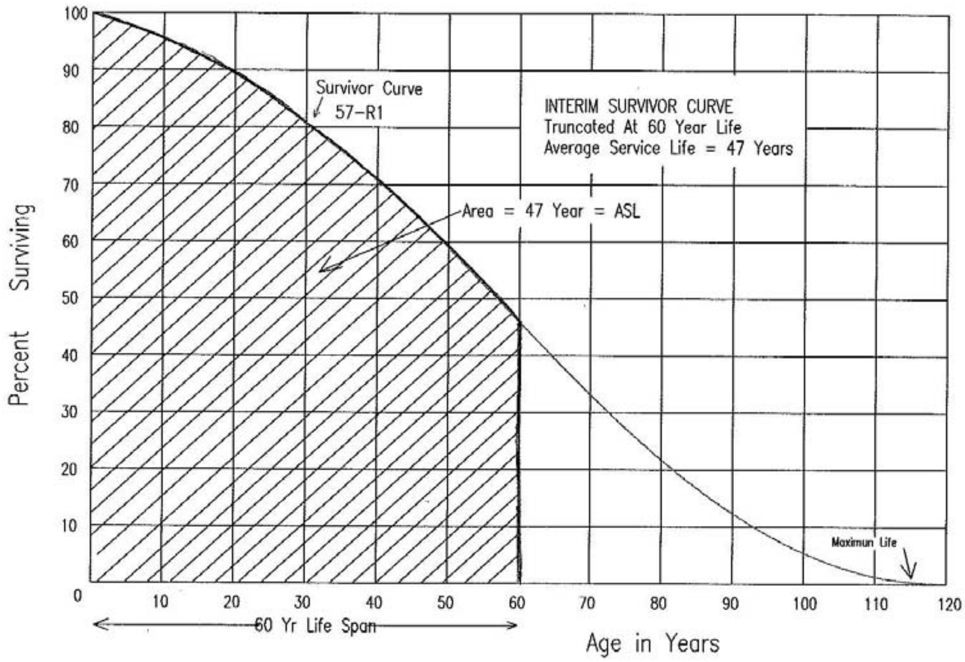

Figure 2 Life Span Type Survivor Curve

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

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

The Life Span Depreciation Rate Equation::

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

ASLs = average service life in years, from *interim* survivor curve truncated at life span.
Final retirements are specifically identified and removed from the depreciation analysis.

Net Salvage = gross salvage - cost of removal

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

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

$$\text{Terminal Net Salvage \%} = \frac{\text{terminal net salvage \$}}{\text{Terminal Retirement \$}} * 100$$

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

F. Treatment of Combustion Turbine Accounts

Staff recommends depreciation analysis treating the Other Production Plant accounts containing predominantly combustion turbine generators and associated facility equipment as a living fleet, using the mass property method. Prior rate case treatment for KCPL and all other recent electric company rates cases in Missouri have depreciation rates set for combustion turbine accounts using the Mass Property method.[64] Staff does not recommend adoption of the Company's (MPS or L&P) request to separately account for each combustion turbine and forecast retirement dates for each combustion turbine.

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

G. General Accounts Left at Prior Ordered Depreciation Rates for Direct Testimony

During Staff's review of the General accounts which the Company proposed switching to an Amortization or Square Curve method, Staff was unable to reconcile differences found between the Company provided historical data and prior case account balances in audit Staff work papers. The accounts involved are accounts 391, 391.01, 391.02, 393, 394, 395, 397, and 398. An example is L&P account 393 (stores Equipment). Staff shows a June 2010 plant balance of $97,441 with a depreciation reserve of $103,727, which indicates this account is over

[64] This is consistent with the Commission's Report and Order In AmerenMissouri's Case No. ER-2010-0036.

accrued by approximately $6,000. The Company proposal claims L&P account 393 has $23,958 in unrecovered deprecation and an additional $117,989 left to depreciate. This raised questions regarding recent corporate office moves and retirements associated with the acquisition, and the possible effect on any depreciation analysis which used this historical data.

At the time of this direct testimony, Staff recommends keeping the depreciation rates for these accounts at the prior case ordered depreciation rates, not switching to an Amortization Method, and not recommending revised rates. For ECORP, this includes account 390 (Structures and Improvements).

H. Whole Life and Remaining Life

Whole Life depreciation rates may be viewed as the current rate of consumption of plant in service, with no correction in the assigned depreciation rate to adjust for any over or under accrued depreciation reserves. The current ordered depreciation rates, Staff Cases A, and Staff Case B use the Whole Life method of depreciation rate calculation. When Whole Life rates are used, an additional depreciation amortization may be assigned to correct reserve imbalances. For Staff recommended Case A, the assigned amortization for each account shown in AR-MPS-1 and AR L&P-1 is to correct for over or under accrued accumulated reserves.

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

Staff recommends the use of Whole Life depreciation rates for MPS, L&P and ECORP for the following reasons:

1. Whole Life rates show the current consumption of capital and provide a direct comparison for review with prior rate case or other company depreciation rates,

2. Whole life rates provide a more consistent depreciation accrual in accounts where large changes in balances may occur from additions and retirements between rates cases that review depreciation.

3. Amortization assigned in conjunction with Whole Life rates allow setting a fixed time to apply the amortization, and

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

I. Interim versus Final (Terminal) Retirements and Net Salvage

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

Retired units which still physically exist have ongoing cost of removal and salvage which may continue for up to 20 plus years.[65] These net salvage costs should continue to be recorded and reflected in the depreciation rate analysis for all plant units as a fleet of production units. The representation of true historical cost for production units will not be reflected in the estimation of depreciation rates if only individual in service units are incorporated into the depreciation analysis, with the final retirement and terminal net salvage history ignored.[66]

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

In Staff's Cases C and D, Staff treated the steam production plant for MPS and L&P as Life span property, and Staff was able to distinguish between interim and final retirements. Interim retirements result in interim net salvage. Final (or terminal) retirements are associated with the removal or dismantling of the retired unit. For Staff's Case C, terminal net salvage was modeled at zero % to be consistent with the Life Span model the Commission approved in AmerenUE Case No. ER-2010-0036. For Staff Case D, terminal net salvage was modeled at a negative 12% to demonstrate the variation in depreciation expense when including or not including terminal net salvage in the analysis.

For all GPE associated companies and divisions (KCP&L, GMO MPS, and GMO L&P), Staff has knowledge of five steam production facilities where approximately 15 boiler/turbine units have been shut down and removed from service. Four of these five steam production facilities, consisting of 11 of the approximate 15 units, have been dismantled and disposed of. The total amount retired for these four steam production facilities is $33,141,318, with the associated cost of removal and salvage of $4,196,600 and $216,812, respectively. The resultant overall composite terminal net salvage rate from this historical steam production plant data is a negative 12%.

Staff Expert/Witness: Arthur W. Rice

X. Current and Deferred Income Tax

A. Current Income Tax

Staff calculated income tax liability in this case consistent with the methodology used in GMO's last rate case, Case No. ER-2009-0090. The adjustments made by Staff begin by taking adjusted net operating income before taxes and adding to or subtracting from net income various timing differences in order to obtain net taxable income for ratemaking purposes. These "add back" and/or subtraction adjustments are necessary to identify new amounts for the tax deductions that are different from those levels reflected in the income statement as revenues or expenses. The adjustments are the result of various book versus tax timing differences and the effect of such differences under separate tax methods: flow-through versus normalization A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes (book purposes) is different than the timing required by the IRS in determining taxable income (tax purposes). 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
- 50% Meals and Entertainment Disallowance
- Contribution in Aid of Construction
- Advances for Construction

Subtractions from Operating Income:

- Interest Expense – Weighted Cost of Debt X Rate Base
- Tax Straight-Line Depreciation
- Tax Depreciation over Straight Line Tax
- IRS Section 199 Domestic Production Activities

The normalization tax method defers the tax deduction taken for tax purposes for those taxes that are taken as tax deduction for ratemaking purposes.

The flow-through tax method essentially provides for the same tax deduction taken as a deduction for ratemaking purposes as is taken for tax purposes.

The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current liability for income taxes. A federal tax rate of 35 percent and a state income tax rate of 6.25 percent were used in calculating MPS and L&P's share of GMO's current income tax liability. This composite tax rate (state and federal combined together) is 38.39%. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

B. Straight Line Tax Depreciation

Annualized book depreciation is a result of multiplying the plant investment at June 30, 2010, the end of the update period used by Staff for this proceeding, by the book depreciation rates being recommended by Staff witness Arthur W. Rice 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/Witness: Paul R. Harrison

C. Deferred Income Tax Expense

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax as the result of the Internal Revenue Code (IRC), the timing difference is given “flow-through” treatment.

When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given “normalization” treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

For most utilities, it is necessary to break out a utility's tax depreciation into two separate components: tax straight-line depreciation and excess tax depreciation. Tax straight-line depreciation is different from book straight-line depreciation due to the different tax basis of property allowed under the tax code. Excess tax depreciation differs from straight-line book depreciation due to the higher depreciation rates allowed in the early years of an asset's life under the current tax code. Most tax basis differences were eliminated for assets placed into service after 1986 due to the Tax Reform Act enacted that year.

Staff's standard deferred income tax adjustment consists of three components:

1. IRS Schedule M timing differences: contributions in aid of construction and advances for construction. These amounts are normalized consistent with Staff's calculation in the prior rate case filing;

2. The tax timing difference between tax straight-line depreciation expense and tax depreciation expense: This treatment is consistent with the normalization calculation in the previous rate case filing; and

3. Excess deferred income taxes resulting from the 1986 Tax Reform Act, which created excess deferred tax amounts associated with depreciation timing differences: As such, an amortization has been created to amortize excess deferred taxes created from the change in tax rates back to customers.

Normally a combination of the above three components make up the amounts recorded as deferred income tax expense.

D. Kansas City Earnings Tax

Staff normalized the Kansas City, Missouri earnings tax (KCET) in this rate case. This is included in the revenue requirement calculations for MPS & L&P as Adjustments E-169.1 and

E-176.1, respectively. The amounts were determined as part of the tax calculation for the KCPL rate case, Case No. ER-2009-090 and included in Staff's Accounting Schedule 11, Income Tax calculation. As discussed below, it is Staff's position that a portion of the KCET tax should be allocated to MPS and L&P. The adjustments to normalize and allocate the earnings tax are necessary to properly reflect an amount for the local Kansas City tax in current rates for MPS and L&P. During the review of KCPL costs, Staff discovered when this tax was made part of the tax calculation in KCPL's last rate case, it overstated costs. When the earnings tax was included in the tax calculation on Staff Accounting Schedule 11 and factored up for income taxes, it was creating a significant difference between the amount of earnings taxes actually paid and the level that was determined in the tax calculation. For example, in KCPL's last rate case, Staff included $887,104 for earnings taxes computed as part of the tax when ultimately the Company actually only paid $74,443 for 2009.

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

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

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

Because the corporate office activities such as management oversight and accounting functions benefits all KCPL, MPS, L&P, it is appropriate to allocate a portion of the earnings taxes to each, just as it is proper to allocate other corporate office costs, like salaries and office rents. Staff believes that 25 percent is an appropriate allocation, and recommends that KCPL conduct an allocation study in the future.

Staff Expert/Witness: Paul R. Harrison

E. Accumulated Deferred Income Tax and Amortization

MPS's and L&P's deferred income tax reserve represents, in effect, a prepayment of income taxes by MPS's and L&P's customers. As an example, because MPS and L&P are 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 a 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 MPS and L&P. Therefore, MPS's and L&P'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.

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

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property.

Staff Expert/Witness: Paul R. Harrison

F. MPS Deferred Income Taxes Accounting Authority Order (AAO)

Staff has also included the accumulated deferred taxes related to the 1990 and 1992 Accounting Authority Orders (AAO) approved by the Missouri Public Service Commission in Case Nos. EO-91-358 and EO-91-360 for MPS in Staff Accounting Schedule, Rate Base Schedule 2. These AAO's deferred the depreciation expenses and carrying costs associated with the life extension construction and coal conversion project at the Sibley Generating Station.

Staff Expert/Witness: Paul R. Harrison

G. Iatan No. 2 Advanced Coal Credit

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

In February 2009, KCPL was served a notice to arbitrate by Empire District Electric Company (Empire), Kansas Electric Cooperative, Inc. (KEPCO) and Missouri Joint Municipal Electric Utility Commission (MJMEUC), joint owners of Iatan 2. The joint owners asserted that they are entitled to receive proportionate shares (or the monetary equivalent) of approximately $125.0 million of qualifying advance coal project credit for Iatan 2. As independent entities, the joint owners are taxed separately and the joint owners do not dispute that they did not, in fact, apply for the credits themselves. Notwithstanding this, the joint owners contend that they should receive proportional shares of the credit. This matter was heard by an arbitration panel in November 2009.

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

GMO owns eighteen percent of the Iatan 2 power plant. Staff asserts that since GMO owns eighteen percent of Iatan 2, it is entitled to receive a proportionate share (or monetary equivalent) of the approximately $125 million of qualifying advance coal project credit for Iatan 2. Even though MPS and L&P are not actually taxed separately for income tax purposes, it is necessary to determine income tax expense for MPS and L&P separately for rate making purposes because they maintain separate rate structures. For rate making purposes, MPS and L&P's cost of service is based upon its own rate base, revenues, expenses and income tax liability. Therefore, Staff has made an adjustment to allocate eighteen percent of the advanced coal credit that KCPL received from the IRS to GMO (MPS and L&P). This equates to approximately $26.5 million.

Because Iatan 2 is allocated between MPS and L&P, it is necessary to allocate an appropriate amount of the $26.5 million for the advance coal credit to each. Staff has allocated MPS and L&P's share of the advance coal credit based on the allocation of Iatan 2 costs between MPS and L&P, 65.4 percent and 34.6 percent, respectively.

Staff Expert: Paul R. Harrison

XI. Fuel Adjustment Clause

A. Recommendation

Staff recommends that the Commission approve, with modifications, the continuation of GMO's Fuel Adjustment Clause ("FAC"). Staff has reviewed the minimum filing requirements documents the Company provided in Schedules TMR2010-1, TMR2010-2, TMR2010-3, TMR2010-4 and TMR2010-5 attached to the pre-filed Direct Testimony of Company witness

Tim M. Rush and believes that with these documents the Company has complied with the minimum filing requirements contained in 4 CSR 240-3.161(3) to inform the public of the Company's requested continuation of and changes to its FAC in this case.

At this time Staff does not have an estimate for the Base Energy Cost for the FAC in this case, but will include its estimate of the appropriate Base Energy Cost when it files its Class Cost-of-Service and Rate Design testimony on December 1, 2010. Staff recommends the Base Energy Cost in the FAC be set equal to the Base Energy Cost in the test year true-up total revenue requirement for this case.

Staff recommends that the Company's FAC tariff be modified to: 1) change the sharing mechanism from 95%/5% to 75%/25% to provide the Company with a more appropriate incentive to keep its fuel and purchased power costs down, 2) include language that the Base Energy Cost in the FAC be set equal to the Base Energy Cost in the test year total revenue requirement in the rate case to assure that the Company does not benefit or is not penalized as a result of the two Base Energy Costs being different in the rate case, and 3) delete two FERC accounts now included in the definition of Purchased Power Costs, since these FERC accounts are for transmission expenses and are not consistent with the definition of fuel and purchased power costs in 4 CSR 240-20.090(1)(B).

Finally, Staff recommends that the Commission order the Company to continue to provide or make available information and documents to assist Staff during its performance of FAC tariff, prudence and true-up reviews.

B. Summary of Current FAC

The Commission first authorized a FAC for GMO in its Report and Order in KCP&L Greater Missouri Operations Company's 2007 rate case (File No. ER-2007-0004) for GMO's then Aquila Networks-MPS (MPS) and Aquila Networks-L&P (L&P) divisions, with the original FAC tariff sheets having an effective date of July 5, 2007. In the subsequent GMO rate case, File No. ER-2009-0090, the Commission authorized continuation with modifications of the GMO FAC. The primary features of GMO's present FAC (tariff sheet numbers 124 through 127.5) include:

- Two 6-month accumulation periods: June through November and December through May;
- Two 12-month recovery periods: March through February and September through August;
- Separate Cost Adjustment Factors ("CAF") for MPS and for L&P;
- Two CAF filings annually not later than January 1 and July 1;
- A 95%/5% sharing mechanism;
- CAF rates for individual service classifications are adjusted for the two GMO service voltage levels, rounded to the nearest $0.0001, and charged on each applicable kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with true-up amount being included in determination of CAFs for a subsequent recovery period.

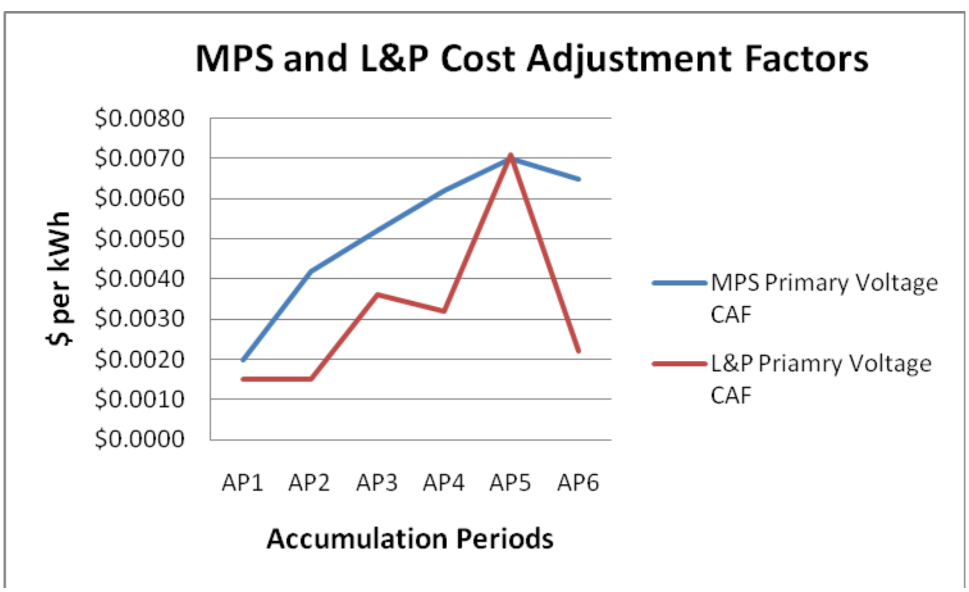
GMO has made six CAF filings (Case/File Nos. EO-2008-0216, EO-2008-0415, EO-2009-0254, EO-2010-0002, EO-2010-0191, and ER-2010-0385), and the resulting changes to the GMO CAFs ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The MPS and L&P Base Energy Cost per kWh rates were originally set in GMO's 2007 rate case (Case No. ER-2007-0004) and were changed as a result of the settlement of GMO's 2009 rate case (Case No. ER-2009-0090) from $0.02538 per kWh to $0.02348 per kWh for MPS and from $0.01799 per kWh to $0.01642 per kWh for L&P.

Staff has filed two prudence review reports concerning its review of the costs of the Company's FAC and found no evidence of imprudent decisions by the Company's management related to procurement of fuel for generation, purchased power and off-system sales. Staff's prudence review reports are in Case Nos. EO-2009-0115 and EO-2010-0167, and cover the periods June 1, 2007 through May 31, 2008 and June 1, 2008 through May 31, 2009, respectively.

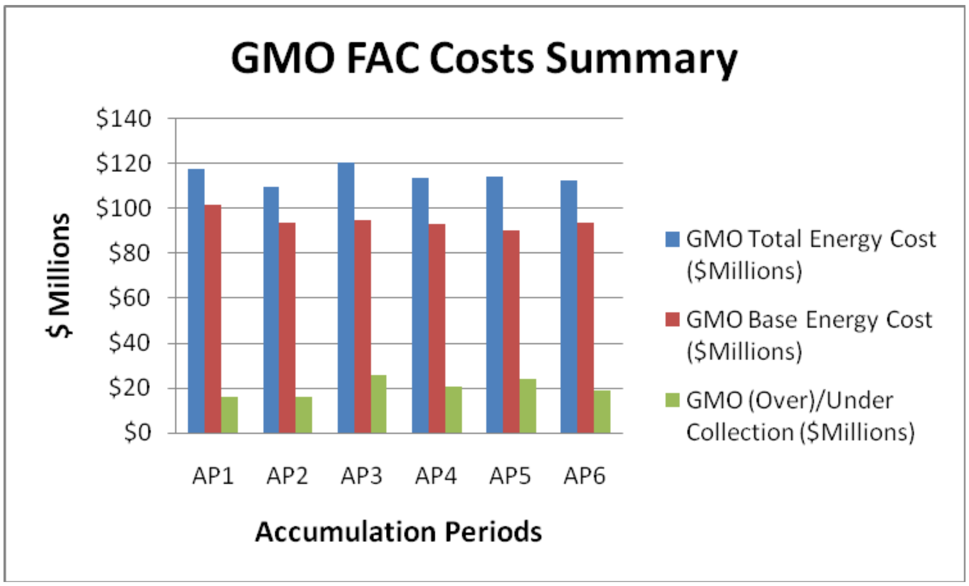
C. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of GMO's FAC.

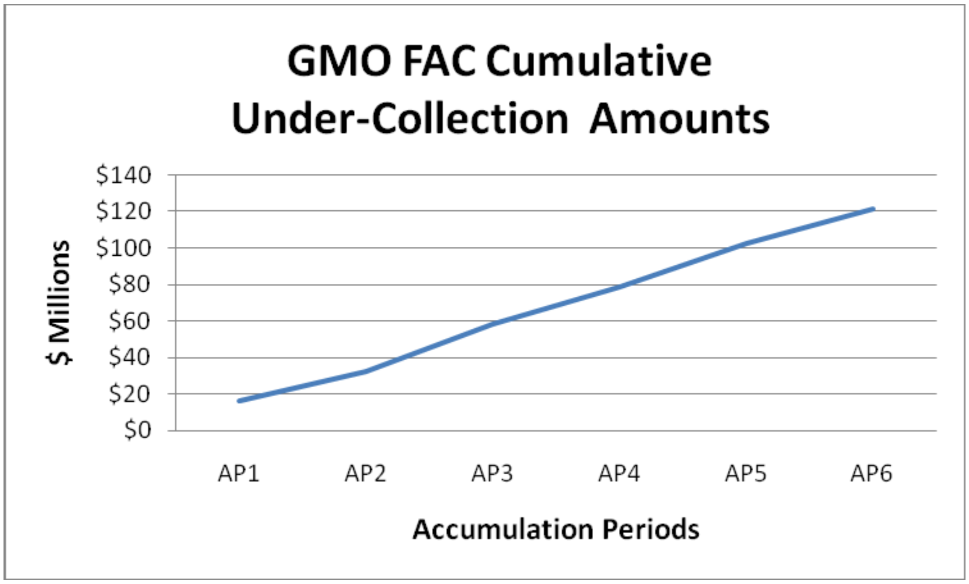
The Company has filed for and received approval of changes to its CAF's for six completed accumulation periods (AP1, AP2, AP3, AP4, AP5 and AP6). The primary voltage CAFs of MPS and L&P for each accumulation period are reflected in the following chart:

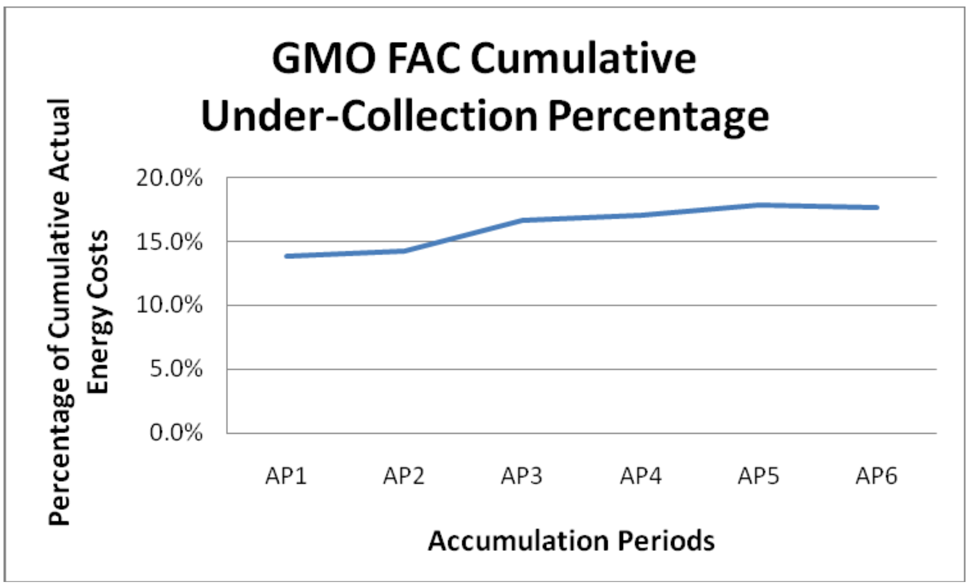


The Company's total actual energy costs have exceeded the base energy costs collected through customers' bills for GMO in each of the six completed accumulation periods. The following chart illustrates the GMO total actual energy costs, the GMO base energy costs as estimated using the Base Energy Cost per kWh rates in the FAC tariff, and the GMO (over)/under collection of actual energy costs for each of the six accumulation periods:



The following two charts illustrate the following information for the first six accumulation periods: 1) cumulative amount of the difference between actual energy costs and the base energy costs as calculated using the Base Energy Cost rates in GMO's FAC tariff sheets, and 2) percentage of cumulative under-collection of the difference between actual energy costs and the base energy costs as calculated using the Base Energy Cost rates in GMO's FAC tariff sheets:





From the above information Staff observes that the FAC under-collected amount over three years of $121 million (18 percent of total actual energy costs of $557 million) is a significant amount for GMO. Staff's analysis and discussion in the **Sharing Mechanism of FAC** section which follows suggests that without the FAC GMO would have lost approximately half of its test year net income before taxes[67] (NIBT) due to under-collection of fuel and purchased power costs less off-system revenue during the timeframe of the FAC's first six accumulation periods.

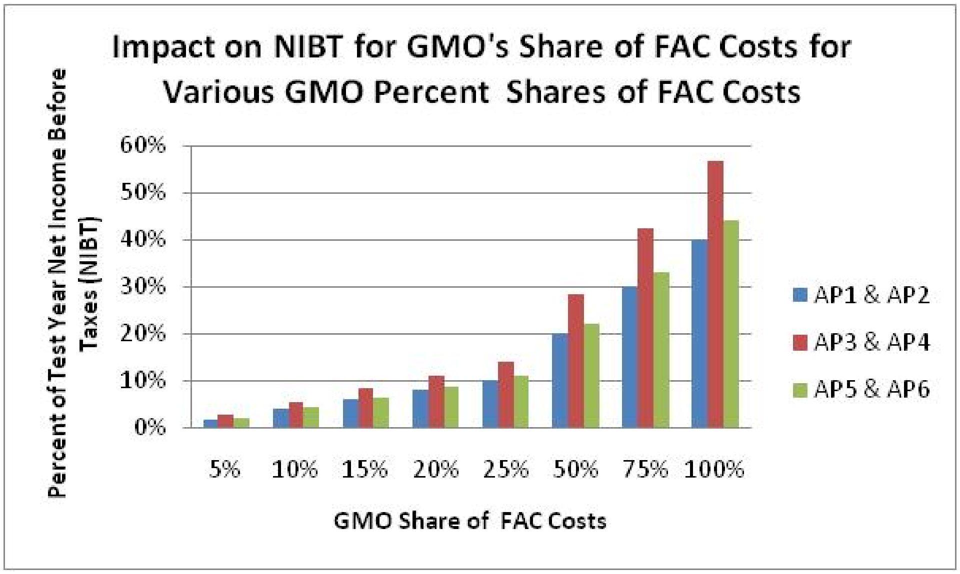
D. Sharing Mechanism of FAC

GMO's FAC has been in effect for over three years which provides Staff with sufficient information that is necessary to evaluate the impact of the current 95%/5% GMO FAC sharing mechanism over the first six accumulation periods and to evaluate several other selected sharing mechanisms for the impact they would have had on the Company's test year net income before taxes. Given its analysis, Staff proposes changing the current 95%/5% FAC sharing mechanism to a 75%/25% FAC sharing mechanism. The Commission has stated the objective of the FAC sharing mechanism is to provide an incentive for the Company to "keep its fuel and purchased power costs down." To do so requires incenting the utility to develop and manage an effective energy procurement process which minimizes energy costs while managing risk of loss of energy supply. The Commission first expressed its view in its Report and Order in Case No. ER-2007-0004 where it first established the current 95%/5% sharing mechanism when it stated on page 54:

> The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

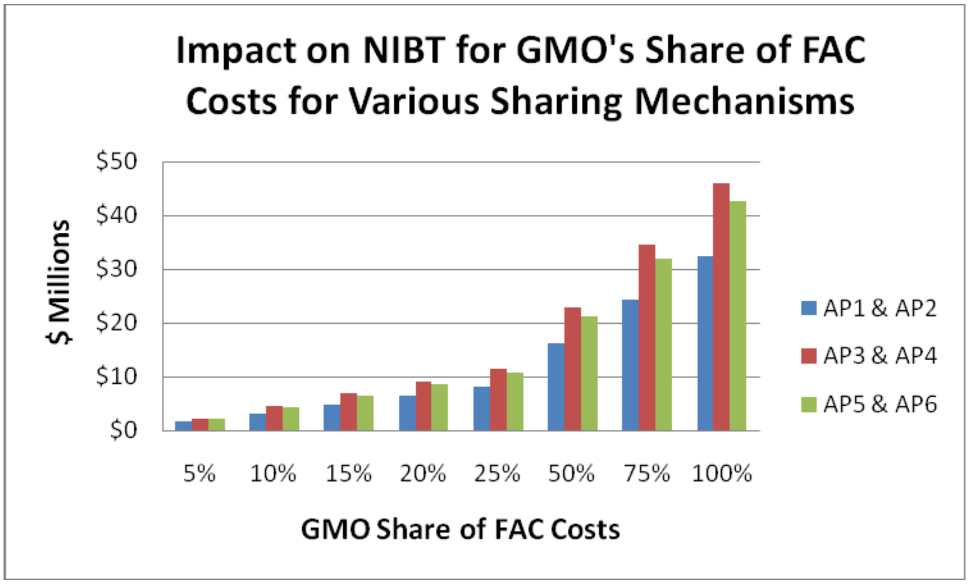
[67] Net income before taxes in Staff Accounting Schedules for the MPS and the L&P test year income statements filed on January 18, 2007 in File No. ER-2007-0004 ($71,817,796 on line 103 Accounting Schedule 9-3 for MPS and $9,263,787 on line 106 of Accounting Schedule 9-3 for L&P) and filed on February 13, 2009 in File No. ER-2009-0090 ($90,051,142 on line 186 of Accounting Schedule 9 (page 5 of 6) for MPS and $6,307,908 on line 191 of Accounting Schedule 9 (page 5 of 6) for L&P).

Staff has evaluated the impacts on GMO's test year net income before taxes of GMO's FAC over the first six accumulation periods with the current 95%/5% sharing mechanism and with several other selected sharing mechanisms. The results of Staff's evaluation follow:



Through this analysis Staff estimates that GMO's 5% share of the total under-collection amount of $121 million during the first six accumulation periods is $6 million and represents 2.3% of the test year net income before taxes ($252 million) for this same period of time. Similarly, Staff estimates that for Company shares of 10%, 15%, 20%, 25%, 50%, 75% and 100% of the total under-collection amount during the first six accumulation periods represent approximately 4.7%, 7.0%, 9.4%, 11.7%, 23.4%, 35.1% and 46.8% of the test year net income before taxes for this same period of time.

The corresponding dollar amounts of the total under-collected amount of $121 million during the first six accumulation periods that the Company would have been responsible for if the Company's share had been 10%, 15%, 20%, 25%, 50%, 75% and 100% is illustrated in the following chart.



Staff considers the approximate $2 million annual under-collected amount, out of an average annual total FAC cost of $40.4 million, the Company has been responsible for under the current 95%/5% sharing mechanism during the first six accumulation periods to be an insufficient incentive for the Company to "keep its fuel and purchased power costs down" by developing and managing an effective energy procurement process to minimize energy costs while managing risk of loss of energy supply. To further illustrate the lack of incentive with the current 95%/5% sharing mechanism, Staff points out that neither in this rate case nor in GMO's last rate case did GMO propose to reset its Base Energy Cost in the FAC it proposed or in its test year total revenue requirements that it filed as part of either of its rate cases, even though GMO had been responsible for approximately $2 million annually of the FAC's under-collected amount during the filed test year period of each rate case.

Staff proposes a 75%/25% sharing mechanism, which for the first six accumulation periods would have resulted in the Company being responsible for approximately $10 million annually of the under-collected amount of the FAC. Measured differently this would be approximately 12% of test year net income before taxes and 5.4% of GMO's actual fuel and purchased power costs during that same period. Staff considers a 75% share of FAC over-and- under-collection amounts to be a point where ratepayers begin to take on a significant portion of the risk of actual FAC costs. By being responsible for 25% of FAC over- and under-collection amounts, GMO would have an appropriate incentive to keep its fuel and purchased power costs down—and to minimize fuel and purchased power costs less off-system sales revenue while managing risk of loss of energy supply.

D. Resetting the Base Energy Cost in the FAC Equal to the Base Energy Cost in the Test Year Revenue Requirement in This Rate Case

Correctly setting the Base Energy Cost in the FAC tariff sheets is critical to both a good FAC and a good FAC sharing mechanism. Staff recommends the Commission require the Base Energy Costs in GMO's FAC be separately set equal to the normalized Base Energy Cost for fuel and purchased power costs less off-system revenue in the test year true-up revenue requirement for MPS and L&P in this case.

The table below shows three cases in which the fuel and purchased power costs less off-system sales revenue used to set the FAC Base Energy Cost per kWh rates is equal to, less than or greater than the fuel and purchased power costs less off-system sales revenue in the test year revenue requirement used to set base rates.

Line	**75%/25% Sharing Mechanism Example**	**Case 1**: Base Energy Cost in FAC **Equal To** Base Energy Cost in Rev. Req.	**Case 2**: Base Energy Cost in FAC **Less Than** Base Energy Cost in Rev. Req.	**Case 3**: Base Energy Cost in FAC **Greater Than** Base Energy Cost in Rev. Req.
a	Revenue Requirement	$ 10,000,000	$ 10,000,000	$ 10,000,000
b	Base Energy Cost in Rev. Req.	$ 4,000,000	$ 4,000,000	$ 4,000,000
c	Base Energy Cost in FAC	$ 4,000,000	$ 3,900,000	$ 4,100,000
	Outcome 1: Actual Energy Cost **Greater Than** Base Energy Cost in Revenue Requirement			
d	Actual Energy Cost	$ 4,200,000	$ 4,200,000	$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
e = (d - c) x 0.75	through FAC	$ 150,000	$ 225,000	$ 75,000
f = b + e	Total Billed to Customers	$ 4,150,000	$ 4,225,000	$ 4,075,000
g = f - d	**Kept/(Paid) by Company**	**$ (50,000)**	**$ 25,000**	**$ (125,000)**
	Outcome 2: Actual Energy Cost **Less Than** Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	$ 3,800,000	$ 3,800,000	$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
i = (h - c) x 0.75	through FAC	$ (150,000)	$ (75,000)	$ (225,000)
j = b + i	Total Billed to Customers	$ 3,850,000	$ 3,925,000	$ 3,775,000
k = j - h	**Kept/(Paid) by Company**	**$ 50,000**	**$ 125,000**	**$ (25,000)**
l = (k + g) / 2	**Expected Kept/(Paid) by Company (Note)**	**$ -**	**$ 75,000**	**$ (75,000)**
Note: Expected amounts based on equal probability of **Outcome 1** and **Outcome 2** occurring.				

Case 1 illustrates that if the Base Energy Cost in the FAC is equal to the Base Energy Cost in the test year revenue requirement, the utility does not benefit nor is it penalized as a result of the level of actual energy costs.

Case 2 illustrates that if the Base Energy Cost in the FAC is less than the Base Energy Cost in the test year revenue requirement, the utility is expected to benefit and customers are expected to be penalized regardless of the level of actual of energy costs.

Case 3 illustrated that if the Base Energy Cost in the FAC is greater than the Base Energy Cost in the test year revenue requirement, the utility is expected to be penalized and customers are expected to benefit regardless of the level of actual energy costs.

These three cases illustrate the importance of setting the Base Energy Cost in the FAC correctly, i. e., equal to the Base Energy Cost in the test year true-up revenue requirement.

E. Recommended Changes to the FAC

Staff recommends the following changes be made to GMO's FAC. Staff will provide exemplar FAC tariff sheets to reflect these changes as part of its Class Cost-of-Service and Rate Design testimony on December 1, 2010:

1. Change the sharing mechanism in GMO's FAC from 95%/5% to 75%/25%;

2. Include language to reset GMO's Base Energy Costs in the FAC equal to the Base Energy Cost test year revenue requirement in each general rate case by changing the first line of the APPLICABLE BASE ENERGY COST section of the FAC to read: "Base Energy Costs in this FAC is equal to the Base Energy Cost in the test year revenue requirement for this general rate case. The Base Energy Costs per kWh for MPS and for L&P are:"; and

3. Delete the reference to FERC Account Numbers 565 and 575 in the definition of factor PP (Purchased Power Costs), since these FERC Accounts are for transmission expenses and are not consistent with the definition of fuel and purchased power costs in 4 CSR 240-20.090(1)(B).

F. Additional Filing Requirements

To aid in its FAC tariff, prudence and true-up reviews, Staff recommends that the Commission order GMO to continue to provide or make available the information and documents described in item 18. c. of the Non-Unanimous Stipulation and Agreement in GMO's 2009 rate case File No. ER-2009-0090 and provided in this Staff Report as Appendix 6, Schedule JAR-2.

Staff Expert: John A. Rogers

XII. Jurisdictional Allocations

The Missouri Public Service Commission sets cost-of-service based rates only for the Missouri retail customers; however, not all the costs a utility incurs are necessarily to provide service to its Missouri retail customers. GMO has both retail and wholesale customers; however, it only serves wholesale customers in the area in which MPS rate schedules apply. GMO has no electric wholesale customers in the area in which L&P rate schedules apply. Because GMO has no electric wholesale customers in the area in which L&P rate schedules apply, there is no Federal Energy Regulatory Commission (FERC) wholesale jurisdiction to consider in the revenue requirement calculation for L&P. Wholesale and retail sales are considered to be in separate "jurisdictions." Because the MPS and L&P rates differ, Staff considers them separately and independently when developing jurisdictional allocators. Some costs to serve a particular jurisdiction may be directly assigned; however, other costs are not directly assignable to a particular jurisdiction and must therefore be allocated among the various jurisdictions. Costs that correlate with energy-generally costs that vary with energy consumption-are denoted as "energy-related" costs. Costs that correlate with demand-generally costs that do not vary with energy consumption, i.e. "fixed costs"-are denoted as "demand-related" costs. Different allocation factors are developed and utilized for each.

Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriate to allocate on the basis of energy consumption. In this Case, jurisdictional allocation factors for demand and energy are calculated to assist in allocating demand-related (fixed) costs and energy-related (variable) costs between two applicable jurisdictions: retail and wholesale operations for MPS. The application of a particular jurisdictional allocation factor is dependent upon the type of cost being allocated. These calculations were performed for MPS only; they are not necessary for L&P because there are no electric wholesale customers in the L&P area.

Staff Expert/Witness: Alan J. Bax

A. Methodology

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the energy requirements of its customers, generally expressed in kilowatts (kWs) or megawatts (MWs), either at an instant in time or averaged over a designated interval of time. System peak demand is the largest electric requirement occurring within a specified period of time (e.g., hour, day, month, season, and year) on a utility's system. In addition, for planning purposes, an amount of kWs or MWs in excess of anticipated system peak demand must be included for meeting required contingency reserves. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each of the two jurisdictions, MPS wholesale and retail, coincident to these system peak demands, is the appropriate basis on which to allocate the costs of these facilities. Thus, the term coincident peak (CP) refers to the load, generally in kWs or MWs, in each of the jurisdictions that coincide with MPS's overall system peak recorded for the time period used in the corresponding analyses.

Staff utilized a 4CP method - based on the monthly seasonal coincident peaks of the four summer months in the test period - to determine the demand allocation factors for MPS. The 4CP method is appropriate for MPS that experiences dominant demands in the four summer months (June through September) in relation to the demands in the other eight months of a year. Utilizing a 1 CP method may be considered if there was an occurrence of a needle peak in a particular month, or possibly a 12 CP method if comparatively similar hourly peaks were experienced in both winter and summer months. In analyzing the monthly demands in calendar year 2009, the test year of the current rate case, these demands are consistent with the monthly demands in the test periods associated with the last several rate cases involving MPS.

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

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

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

c. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

- Retail Jurisdiction: 0.9954
- Wholesale Jurisdiction: 0.0046
- Total: 1.0000

Staff Expert/Witness: Alan J. Bax

2. Energy Allocation Factor

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

- Missouri Retail Operations: 0.9943
- Wholesale Operations: 0.0057
- Total: 1.0000

These jurisdictional demand and energy allocation factors were provided to Staff Witness Cary Featherstone, who used them to allocate related costs to the Missouri retail jurisdiction.

Staff Expert/Witness: Alan J. Bax

B. Application

As stated above, L&P only has Missouri retail sale; therefore, for it, there are no jurisdictions among which costs need be allocated. In contrast, as stated above, MPS operates within the Missouri retail jurisdiction, and in the wholesale jurisdiction regulated by FERC. Therefore, it is necessary to specifically identify, then allocate and/or assign, MPS's investment and expenses between these two jurisdictions. In order to develop a fully comprehensive cost of service analysis to identify the revenue requirements for MPS, all of MPS's costs for plant investment and the costs appearing on its income statement, must be appropriately placed in each of the jurisdictions it serves (Missouri Retail and Wholesale).

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

MPS' generation and transmission facilities, used to produce and transport electricity to MPS retail customers in Missouri and the FERC wholesale customers, are predominantly considered fixed assets. The costs and investments of these assets, as well as the related depreciation reserve accounts, are apportioned to the two jurisdictions on the basis of demand. As stated above, Staff applied the demand factor it developed for the Missouri retail jurisdiction, based on the 4 CP methodology, to allocate the appropriate portion of these aforementioned assets in its determination of MPS's cost of service to the Missouri retail jurisdiction. Staff has consistently used the 4CP method to allocate costs in previous MPS rate cases. All of MPS's distribution plant assets are located in Missouri; therefore, the costs of all of this plant need only be allocated between the Missouri retail and the wholesale jurisdictions. Staff used the actual amounts of distribution plant investment at June 30, 2010 to develop allocation factors for distribution plant and reserve to quantify only the distribution plant specific to Missouri operations.

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

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

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

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

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

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

L&P has unique characteristics regarding its electric operations. While L&P does not have any other state of federal jurisdiction in which it operates, it does have separate industrial steam system to assign plant investment and costs. Some of L&P operating costs are directly assigned but others have to be allocated between the two electric and steam operating systems. A variety of allocation factors are used to "separate" the two operating systems from one another. Staff primarily relied on the allocation factors used by the Company to accomplish this separation of the two operations. While GMO did not file a steam rate case, it still was necessary to separate out the steam operations from the electric operations to develop a stand-alone revenue requirement calculation for the L&P electric operations.

Staff Expert/Witness: Cary G. Featherstone

XI. Transition Cost Recovery Mechanism

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

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

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

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

> Substantial and competent evidence in the record as a whole supports the conclusions that: (1) the Applicants' calculation of transaction and transition costs are accurate and reasonable; (2) in this instance, establishing a mechanism to allow recovery of the transaction costs of the merger would have the same effect of artificially inflating rate base in the same way as allowing recovery of an acquisition premium; and

> (3) the uncontested recovery of transition costs is appropriate and justified. The Commission further concludes that it is not a detriment to the public interest to deny recovery of the transaction costs associated with the merger and not a detriment to the public interest to allow recovery of transition costs of the merger.
>
> If the Commission determines that it will approve the merger when it performs its balancing test …, the Commission will authorize KCPL and Aquila to defer transition costs to be amortized over five years. (Footnote omitted.)

In the footnote 930 omitted above, the Commission stated:

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

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

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

KCPL and the Kansas Commission Staff agreed to an amount of transition costs recovered from the Kansas customers in the merger application filed with the

Kansas Commission. This amount of recovery in Kansas is $10 million over five years [Kansas Commission Docket No. 07-KCPE-1064-ACQ].

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

In examining the Company's documented regulated synergy savings in relation to the table of relevant dates previously provided, KCPL retained all synergy savings realized from July 14, 2008 to September 1, 2009. Assuming the savings in Quarter 3 of 2009 occurred ratably over the quarter, KCPL retained over $52.7 million of synergy savings before any benefits flowed to ratepayers. KCPL has identified total regulated transition costs of $51.9 million.

Comparing the transition costs to the savings identified in the table above KCPL has already recovered the entire amount plus an additional $886,948 [$52,749,210 through September 1, 2009 savings less $51,862,262 of transition costs].

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

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

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

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

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

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

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

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

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

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

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

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

Staff Expert/Witness: Keith A. Majors

Appendices

Appendix 1 - Staff Credentials

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

Appendix 3 - Support for Jeffrey Energy Center FGD Rebuild Project Adjustment – Keith A. Majors

Appendix 4 - In-Service Criteria and Staff Evaluation Notes - David W. Elliott

Appendix 5 - Support for Capacity Requirements and Iatan 2 Allocations - Lena M. Mantle

Appendix 6 - Relevant Pages of Energy Efficiency Advisory Groups Status Report and Additional Filing Requirements for the FAC - John A. Rogers

Appendix 7 – GMO Customer Program Expenditures - Henry E. Warren

Appendix 8 - Support for Transmission Tracker Testimony - Daniel I. Beck

Appendix 9 - Staff Recommended Depreciation Rates - Arthur W. Rice

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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 89-90, 202-205; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J Bax

Alan J. Bax

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Daniel I. Beck, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 160-166; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Daniel I Beck

Daniel I. Beck

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn

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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF WALT CECIL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Walt Cecil, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 68-69, 70-71, 87-89 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Walt Cecil

Walt Cecil

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn

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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 Electric Service	))))	File No. ER-2010-0356

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 58-59, 61-63, 81-83, 86, 90 ; 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 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-9, 205-210; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Cary G. Featherstone
Cary G. Featherstone

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn
Notary Public

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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF CAROL GAY FRED

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Carol Gay Fred, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 150 - 154; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Carol Gay Fred

Carol Gay Fred

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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My Commission Expires: October 01, 2011
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Nikki Senn

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AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Randy S. Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 166; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy S. Gross

Subscribed and sworn to before me this 17th day of November, 2010.

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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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 53-55, 76-79, 79-81, 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 and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

V. William Harris

V. William Harris

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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Nikki Senn

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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 Electric Service	))))	File No. ER-2010-0356

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 115-120, 182-190; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Paul R. Harrison

Paul R. Harrison

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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My Commission Expires: October 01, 2011
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Nikki Senn

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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 Electric Service	))))	File No. ER-2010-0356

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 103-110, 120-123, 130, 149; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Charles R. Hyneman

Subscribed and sworn to before me this 17th day of November, 2010.

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

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

Hojong Kang

Hojong Kang

Subscribed and sworn to before me this 17th day of November, 2010.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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OF THE STATE OF MISSOURI

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AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Shawn E. Lange

Shawn E. Lange

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
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Nikki Senn

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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 38-41, 47-50, 55-56, 128-130, 133-134, 141, 156-158; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Karen Lyons

Karen Lyons

Subscribed and sworn to before me this 17th day of November, 2010.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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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 Electric Service	))))	Case No. ER-2010-0356

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 41-47, 56-57, 141-144, 158-159, 210-221; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Keith A. Majors

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 84 - 86; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

Subscribed and sworn to before me this 17th day of November, 2010.

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 90-103; 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 17th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Amanda C. McMellen, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 72-73, 79, 135, 138-139; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Amanda C McMellen

Amanda C. McMellen

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

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 Electric Service	))))	File No. ER-2010-0356

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 9-38; 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 17th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

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 Electric Service	))))	File No. ER-2010-0356

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 50-53, 55, 110-115, 124-128, 131-133, 136-138, 139-140, 159; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief and that he conducted his audit activities in accordance with Generally Accepted Auditing Standards (GAAS).

Bret G. Prenger
Bret G. Prenger

Subscribed and sworn to before me this 17th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF ARTHUR W. RICE, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Arthur W. Rice, PE, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 166-182; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Arthur W Rice P.E.
Arthur W. Rice, PE

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 144-148, 190-201 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A Rogers
John A. Rogers

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF HENRY E. WARREN, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Henry E. Warren, PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 154 - 156; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E Warren

Henry E. Warren, PhD

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF CURT WELLS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Curt Wells, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 63-65, 69-70, 71-72, 73-76 ; 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.

Curt Wells

Curt Wells

Subscribed and sworn to before me this 17th day of November, 2010.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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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 Electric Service	))))	File No. ER-2010-0356

AFFIDAVIT OF SEOUNG JOUN WON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 66-67; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won

Subscribed and sworn to before me this 17th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public