GMO-210

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.

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[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.

[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

[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

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

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

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

NP

** __________ **, 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

<u>2. Oil and Fuel Additive Inventories</u>

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

1. Jeffrey Energy Center Unit 2 Scrubber 2 In-Service

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

[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.

[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 Annualization 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

1. Customer Discounts

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%)

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

3. Other Revenue Accounts

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

1. Fixed Costs – Fuel Adders

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.

[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

<u>9. Hourly Net System Loads</u>

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

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

12. Allocation of Iatan 2 Capacity Between MPS and L&P

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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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

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.