MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

FILED[2]
NOV 0 9 2009
Missouri Public
Service Commission

MISSOURI GAS ENERGY
A Division of Southern Union Company

CASE NO. GR-2009-0355

Jefferson City, Missouri
August 2009

** Denotes Highly Confidential Information**

NP

Staff Exhibit No. 39
Case No(s). GR-2009-0355
Date 10-26-09 Rptr XF

COST-OF-SERVICE REPORT

COST OF SERVICE REPORT

I. Executive Summary

Staff's Revenue Requirement Recommendation

The Staff has conducted a review of all cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise Missouri Gas Energy's (MGE or Company) revenue requirement. The ordered test year for this case is the twelve months ending December 31, 2008, which also constitutes MGE's most recent fiscal year. The test year update period ordered for this case is the four months ended April 30, 2009. The Staff's recommended revenue requirement for MGE based upon updated results through April 30, 2009 is approximately $17,084,407 at the Staff's recommended midpoint rate of return.

Impact of Staff's Revenue Requirement on Retail Rate Revenue

The Staff's recommended revenue requirement of $17,084,407 would represent an approximate increase in MGE's total non-gas retail rate revenue of 9.25%. This increase would pertain to MGE's margin revenues only, and does not include MGE's gas cost revenues. The impact of the Staff's recommended revenue requirement for each of MGE's rate classes will be discussed in the Staff's rate design and class cost of service report that is to be filed on September 3, 2009. It should be noted that a portion of the Staff's general rate increase recommendation has already been passed on to MGE's customers through periodic Infrastructure System Repair Surcharge (ISRS) rate filings made by MGE. Since the Company's last general rate increase in 2006, rate increases totaling $4,115,945 have been approved by the Commission and charged to MGE's customers through the ISRS rate mechanism. Once rates ordered by the Commission as a result of this proceeding become effective, the current ISRS rate element will be zeroed out and the amounts formerly collected through the ISRS surcharge will then be part of MGE's general retail rates. When the rate increases associated with past MGE ISRS filings are taken into account, the amount of the Staff's recommended incremental rate increase in this case would equal $12,968,462, or 7.02%.

II. Background of Rate Case

Missouri Gas Energy is a local gas distribution utility serving approximately 500,000 customers in 155 western Missouri communities.

MGE is a division of Southern Union Company (SU). SU operates in the natural gas gathering, processing, transmission and distribution industries. SU owns and operates one of the nation's largest natural gas pipeline systems. Corporate costs incurred by SU are allocated to SU affiliates, including MGE.

MGE last received authorization for a general rate increase from the Commission in Case No. GR-2006-0422, in a Report and Order issued on March 22, 2007, with the new rates effective on March 30, 2007. In its Report and Order, the Commission granted MGE an annual rate increase of $27,206,968.

III. True-Up Recommendation

In its direct testimony filing on April 2, 2009, MGE requested that a true-up audit be performed to measure major components of its revenue requirement out through September 30, 2009. In its filing entitled "Staff's Response to Position Regarding Test Year and True-up Period," dated April 28, 2009, the Staff stated that it would make its recommendation to the Commission concerning the need for a true-up audit in this proceeding as part of its direct filing.

A test year update period reflects material changes to the Staff's case through a date near the conclusion of the Staff's audit. In contrast, true-ups are re-audits and updates of major elements of a utility's revenue requirement beyond the end of an ordered test year and test year update period. True-ups are not required for every rate proceeding, and typically are only ordered when a utility can demonstrate they expect to incur material changes to their revenue requirement after the end of the ordered test year update period but prior to the operation-of-law date in the case.

In this case, MGE has asserted that it expects to incur a material increase to its revenue requirement past the April 30, 2009 end of the true-up period through September 30, 2009. MGE witness Michael Noack in his Updated Test Year Direct Testimony filed June 19, 2009 at pages 2-3, recommended that a true-up audit be authorized in this case, stating:

> MGE continues to believe that a true-up audit is necessary and appropriate in this proceeding for several reasons. First, MGE has budgeted approximately $12,000,000 of capital investment that it plans to plan in service between June 30, 2009 and September 30, 2009. This investment represents approximately $1,700,000 of additional annual revenue requirement.
>
> Second, MGE plans to hire approximately 39 additional employees during the summer of 2009. This includes 25 outside plant personnel that would add approximately $1,500,000 to the Company's annual revenue requirement. MGE also plans to hire at least 4 customer service representatives during the summer of 2009 to fill vacancies in time to be trained for the 2009/2010 winter season. This would add approximately $240,000 to the annual MGE revenue requirement.
>
> Lastly, to the extent the Commission uses a capital structure based on the Company's actual debt and equity (without conceding the appropriateness of such an approach), because MGE expects the equity ratio to increase during the true-up period resulting in a higher revenue requirement, MGE would want that structure to reflect the Company's most current percentages.

The Staff believes that MGE has adequately justified the need for a true-up audit in this proceeding, and accordingly recommends that the Commission order such an audit through September 30, 2009 in this proceeding. If a true-up is authorized by the Commission, the Staff intends to true-up the following components of MGE's revenue requirement:

RATE BASE:

Plant in service
Depreciation reserve
Deferred taxes
Related cash working capital effects.
Materials and supplies
Prepayments
Customer deposits
Customer advance for construction
Gas inventory
Prepaid pension asset and pension tracker assets

CAPITAL STRUCTURE:

Rate of Return
Capital Structure

INCOME STATEMENT:

Revenues for customer growth
Payroll - employee levels and wage rates
Rate case expense
Bad debt expense
Depreciation and amortization expense
Related income tax effects
Pensions and OPEBs
Injuries and damages

IV. Major Issues

MGE filed its case based upon a test year ending December 31, 2008. Both the Staff and MGE updated the major components of the Company's revenue requirement through April 30, 2009. The major known methodological or conceptual differences between the Staff and the Company as reflected in their respective direct testimony filings include the following issues along with their approximate dollar value:

Rate of Return – Issue value – ($11.2 million) The Company's case assumed an 11.25% return on equity (ROE), while the Staff is recommending an ROE range from 9.25% to 9.75%. The Company is also recommending a short-term debt cost rate of 4.92%, while the Staff advocates a rate of 0.89% for this capital structure component.

Corporate Allocations – Issue Value – ($3.2 million) - The Company is seeking rate recovery of approximately $5.7 million in allocated costs from its parent, Southern Union. The Staff believes this amount should be significantly reduced because of excessive compensation awarded to Southern Union's officers, incentive compensation that is based on shareholder benefit and measurements, unjustified increases in number of corporate employees, and other reasons.

Environmental Costs – Issue Value – ($4.3 million). MGE seeks recovery of its test year environmental remediation costs of $5.2 million (net of insurance recoveries). The Staff believes rate recovery of $940,000 is an appropriate amount for this item, which it argues is a more normal level and also takes into account MGE's ongoing effort to collect some amount of its environmental expenditures from third parties.

Cash Working Capital – Issue Value – ($2.25 million). MGE's sponsored lead-lag study advocates a collection lag of 28 days. The Staff believes this lag is overstated because it improperly reflects bad debts in its calculation. The Staff also disagrees with a number of MGE's sponsored expense lags.

OPEBs – Issue Value – ($750,000). The Staff alleges that MGE has failed to properly fund its external trust fund mechanisms with the monies it has received from customers for OPEBs calculated according to FAS 106. The Staff contends that MGE should make a shareholder contribution to its OPEBs trust funds to make customers whole for their prior payments in rates for this funding.

Other significant issues may arise between the Staff and MGE as this case progresses. In addition, the Office of the Public Counsel (OPC) and other interveners may take positions in this proceeding that vary significantly from those of the Staff and MGE as well.

V. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return (ROR) of 7.19 percent to 7.45 percent for MGE. The Staff's rate of return recommendation is based on a recommended return on common equity (ROE) of 9.25 percent to 9.75 percent, midpoint 9.50 percent, applied to a proxy group average common equity ratio of 51.06 percent. The Staff's recommended ROE is driven by applying a single-stage, constant-growth discounted cash flow (DCF) analysis to a group of comparable companies. The Staff continues to believe that the DCF methodology is the most reliable method available for estimating a utility company's cost of common equity.

In its Capital Asset Pricing Model ("CAPM") analysis, Staff's use of historical earned risk premiums along with current U.S. Treasury bond yields results in lower estimated costs of common equity than indicated by the DCF analysis. Although Staff's traditional CAPM analysis is insightful, Staff did not adjust its DCF-driven recommendation downward because of the lower CAPM results. Although Staff's recommended ROE in this case was not influenced by the lower CAPM results, Staff will provide other information that lends some credibility to these lower estimates and, therefore, supports the reasonableness and conservativeness of Staff's estimated cost of common equity for MGE.

The Staff is recommending the use of a hypothetical capital structure in this case. The Staff's hypothetical capital structure recommendation is based on the proxy group's average capital structure for the most recently reported fiscal quarter, with the exception of short-term debt. Staff averaged the last four quarters of short-term debt and then deducted the construction work in progress (CWIP) balance provided in each proxy group company's most recent Securities and Exchange Commission (SEC) Form 10-K filing. Schedule 9, contained within Appendix 2 attached to the Report, presents the proxy group capital structure and associated capital ratios. Staff's resulting recommended ratemaking capital structure consists of 51.06 percent common stock equity, 40.47 percent long-term debt, and 8.47 percent short-term debt.

The Staff's embedded cost of long-term debt recommendation of 5.92 percent is based on the proxy group's average embedded cost of long-term debt updated through the most recent fiscal quarter for each comparable company. Staff determined the embedded cost of debt by calculating each comparable company's weighted averaged cost of debt and then calculating a simple average of the individual debt costs. Staff then added 10 basis points to this estimate to allow for issuance costs.

The Staff's recommended cost of short-term debt of 0.89 percent was based on a simple average of the weighted average cost of short-term debt of the two "A" rated companies in the proxy group.

The Staff has prepared two attachments and 20 schedules that support its findings and recommendations in the cost of capital area. The attachments contain explanations of the DCF method and the CAPM. These attachments are denoted as Attachments A and B, respectively, to this Report. The schedules present numerical support for the Staff's rate of return recommendation, and are numbered as Schedules 1 through 20. Both attachments and 20 schedules can be found within Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

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

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

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

---

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

The Court specifically stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[2]

In the Hope case the Court stated:

> The rate-making process, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated . . . that "regulation does not insure that the business shall produce net revenues" . . . it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[3]

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

While the legal requirements announced in the Hope and Bluefield cases have not changed, it is important to recognize that the methodology used to estimate a reasonable rate of

---

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

return has evolved considerably since these cases were decided over 60 years ago. In fact, two of the most commonly used models in making rate of return recommendations, the DCF model (as used in utility regulatory ratemaking proceedings) and the capital asset pricing model (CAPM), did not even become a part of mainstream finance until the 1960s. Likewise, capital markets are not confined to regional boundaries when determining the most efficient use of capital.

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

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

It is generally recognized that authorizing an allowed return on common equity based on a utility's cost of common equity is consistent with a fair rate of return. It is for this very reason that the discounted cash flow (DCF) model is widely recognized as an appropriate model to utilize in arriving at a reasonable recommended return on equity that should be authorized for a utility. The concept underlying the DCF model is to determine the cost-of-common-equity capital to the utility, which reflects the current economic and capital market environment. For example, a company may achieve an earned return on common equity that is higher than its

---

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

cost of common equity. This situation will tend to increase the share price. However, this does not mean that this past achieved return is the barometer for what would be a fair authorized return in the context of a rate case. It is the lower cost of capital that should be recognized as a fair authorized return.

The authorized return should provide a fair and reasonable return to the investors of the company, while ensuring that ratepayers do not support excessive earnings that could result from the utility's monopolistic powers. However, this fair and reasonable rate does not guarantee any particular level of return to the utility's shareholders.

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

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

C. Economic Conditions

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

The world and the U.S. economy continue to experience uncertain times. This makes the estimation of a fair and reasonable cost of capital a tougher task than usual. Not only is the estimation of the cost of capital difficult, but determining what is reasonable and fair during the current deep recession is even more difficult. I will provide the Commission with what I believe to be a reasonable estimate of the current cost of capital for a natural gas distribution utility company of at least investment grade credit quality. The challenge in estimating the cost of capital in today's environment comes from the fact that there is a much larger difference in required risk premiums for riskier investments compared to safer investments. The challenge is evaluating how investors view regulated utility companies in this risk spectrum and whether the current economic environment has impacted their expectations for utilities' expected cash flow growth. Not only has the risk premium spread between U.S. Treasury bonds and corporate bond yields increased, but the spread between high-grade corporate bonds and low-grade bonds have increased. Quite simply, investors are now less willing to provide cheaper capital for riskier investments. However, this does not necessarily translate into a higher cost of capital for safe investments.

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

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

According to a recent article in the *Wall Street Journal (WSJ*[6], after its meeting on August 11 and 12, 2009, the Fed indicated that it plans to

---

[6] Sudeep Reddy, "Fed Set to Trim Major Lifeline," The Wall Street Journal, August 13, 2009, p. A2.

> ...conclude its purchase of $300 billion in U.S. government debt-designed to lower long-term interest rates-by the end of October. The central bank will slow the pace of remaining purchases in order to "promote a smooth transition in markets."
>
> The decision not to expand the Treasury purchases is a key step in the Fed's slow withdrawal of support for the financial system and is a sign that the Fed believes the worst of the downturn is over...
>
> ...The Fed kept its target for short-term interest rates near zero and said it will remain there for the foreseeable future. It also warned that the economy "is likely to remain weak for a time" as consumers and businesses face continued headwinds.

Consequently, it appears that most of the Fed's attention still concerns strategies associated with injecting cash through purchases of U.S. government debt. Because the Fed still plans to inject additional cash into the markets, it would seem that any movement on the Fed Funds rate would occur after the Fed completes its less routine methods of attempting to stimulate the economy. It is also interesting to note the Fed's view that the economy will "likely remain weak for a time." Although the benefit of owning utility stocks is to provide return protection against recessions, it would seem that lower growth in the economy would at the very least cause one to conservatively estimate expected growth rates for utilities.

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

Long-term interest rates, as measured by Thirty-year Treasury bonds (30-year T-bonds), dropped to historically low levels at the end of 2008 and early 2009. However, they have since started to return to levels more consistent with recent years. As of June 2009, the yield on 30-year T-bonds averaged 4.52 percent (see Schedule 4-2), which is an increase from an all-time low in December 2008 of 2.87 percent. However, because of investors' concerns about the economy during the last quarter of 2008, the average utility bond yield increased to as high as 7.80 percent, as of November 2008. The spread between the utility bond yields and 30-year T-bond yields hit an historical high of 400 basis points in December 2008 (see Schedule 4-4). As of June 2009, the average utility bond yield was 6.54 percent. As a result, the spread between the utility bond yields and 30-year T-bond yields decreased to 202 basis points in June 2009, half of the spread last December. The decrease in utility bond yields to 6.54 percent represents a decrease of approximately 125 basis points since its recent peak in November 2008. Although average utility bond yields (inclusive of bonds rated from "Aa" to "Baa" by Moody's) have dropped back to levels experienced before the credit crisis in the fall of 2008, the spread between higher credit quality bonds and lower credit quality bonds remain higher than recent historical averages. Whereas, during a more stable economic environment the spread between "A" rated utilities and "Baa" rated utilities is typically around 30 basis points, as of June 2009, this spread was 110 basis points according to the July 2009 *Mergent Bond Record*. The spread tends to be even smaller when evaluating the difference between an "Aa" rated utility bonds and an "A" rated utility bonds. This spread is typically around 15 basis points. As of June 2009 this spread was only 7 basis points. This results in a spread of 117 basis points between an "Aa" rated utility and a "Baa" rated utility. This represents a 160 percent increase over the spread during more stable economic times, but much lower than the percentage increase in spreads that occurred in the fall of 2008, which approached an almost 400 percent increase over the traditional 45 basis point spread. Consequently, although the cost associated with being less creditworthy is still higher than before the credit crisis, it has declined significantly since the fall of 2008. It is important to understand changes in the spreads between debt rating categories because this provides insight on the additional return investors require to accept increased risk.

Because the monthly utility bond yield data available from Staff's subscription to *Mergent Bond Record* usually has about a month lag, Staff reviewed more recent spot-yield information from Value Line. According to the July 24, 2009 issue of the *Value Line Selection and Opinion*, the yield on "BBB" rated utility bonds was 7.19 percent as of July 15, 2009. Based on the 30-year T-bond yield of 4.49 percent as of the same day, the spot yield spread was 270 basis points. This compares to a spread of 526 basis points between the average yield for "BBB" rated utility bonds and the 30-year T-bond for the month of December 2008. Although Staff is providing information on spot yields for sake of providing current data, Staff does not recommend using spot yields when making cost of capital determinations. It is important to evaluate yields over a longer period for purposes of making a responsible rate of return recommendation.

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the July 10, 2009, issue of *The Value Line Investment Survey: Selection & Opinion*, for the second quarter of 2009 the Dow Jones Industrial Average (DJIA) increased by 11.0 percent, the Standard & Poor's (S&P) 500 increased by 15.2 percent, the NASDAQ Composite Index (NASDAQ) increased by 20.0 percent, and the Dow Jones Utility Average (DJUA) increased by 8.6 percent. According to the same publication, for the six months ended June 30, 2009, the DJIA declined 3.8 percent, the S&P 500 increased by 1.8 percent, the NASDAQ composite increased by 16.4 percent, and the DJUA declined 3.5 percent.

As can be seen from the above, the DJUA has generally lagged the other indices, with the exception of its slightly smaller decline than the DJIA for the first six months of 2009. It is not surprising that other indices have generally outperformed the DJUA considering that investors may be expecting an improvement in the economy. Stocks of industries that tend to be more reactive to economic cycles ("cyclical stocks") tend to outperform industries that are less reactive to economic cycles during periods in which the economy begins to improve.

Although the DJUA is one of the more widely published utility indexes, it should be used with caution for purposes of drawing inferences about possible trends in regulated utilities' cost of capital because many of the companies in the DJUA have non-regulated operations that at least contribute to their performance. None of Staff's comparable companies are included in the DJUA. Therefore, Staff does not consider the DJUA as a good proxy group for MGE. However, comparing utility index results to the rest of the stock market can provide insight on the value being placed on utility stocks in general.

Utility indices can also vary in their results. For example the Value Line Utilities Group, which is composed of "utility" companies followed by Value Line, increased by 8.6 percent for the second quarter of 2009, which is the same compared to the 8.6 increase for the DJUA. The Value Line Utilities Group decreased 5.3 percent for the six months ended July 30, 2009 compared to the DJUA's decrease of 3.5 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation. However, during the first part of 2009 it appears that the DJUA and the Value Line Utilities Index have performed similarly.

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

The Value Line Investment Survey: Selection & Opinion, May 29, 2009, estimates inflation to be 0.00 percent for 2009, 2.00 percent for 2010 and 2.30 percent for 2011. *The Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2009-2019*, January 2009, forecasts an inflation rate of 0.10 percent for 2009, 1.70 percent for 2010 and projects inflation of 1.80 percent for 2011 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury Bills, are estimated to be 0.20 percent in 2009, 0.50 percent in 2010 and 2.00 percent in 2011 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.00 percent in 2009, 4.30 percent in 2010 and 4.50 percent in 2011.

The most recent monthly rate for three-month U.S. Treasury bills was 0.18 percent (see Schedule 5). The most recent monthly rate for long-term Treasury bonds was 4.52 percent (see Schedule 5).

Gross domestic product (GDP) is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to decrease by 3.10 percent in 2009, increase by 1.40 percent in 2010 and increase by 2.80 percent in 2011. The *Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2009-2019*, stated that real GDP is forecasted to decrease by 2.20 percent in 2009, increase by 1.50 percent in 2010, and is projected to increase by 4.20 percent in 2011 (see Schedule 5).

*The Value Line Investment Survey: Selection & Opin*ion, July 10, 2009, stated the following in its Economic and Stock Market Commentary:

> **We expect the economy to make just grudging progress during the final six months of 2009**, with key sectors, such as autos and housing, unlikely to make material inroads at this time. Elsewhere, however, things are looking better, as we are starting to see improvement in retailing and personal income. Moreover, we think we will see further strides made in these two areas going forward. Such gains might well allow the economy---which contracted by 5.5% in the first quarter of 2009 and may have dipped by 2% in the just-ended period---to end the third quarter with little or no change. A slight uptick in growth---perhaps 1%-2%---is possible during the fourth quarter of the year.
>
> **It is hard to see the recovery catching fire until housing prices start to rebound**, and that probably will not occur until late in 2010 or even in 2011. In fact, we may be six months, or more, away from seeing a bottom in housing prices. As long as home prices are falling, consumers will feel less wealthy and may not spend the sums needed on cars and other consumer goods to put the economy back on a solid growth path.
>
> **We may be looking at a low-key business recovery for some time.** Our sense is that the nation's gross domestic product will increase by 2%, or so, during 2010, followed by more normalized growth of 3%, or more, in 2011 and 2012. By then, we would expect the next long housing up cycle to be well under way.
>
> **A major near-term challenge for investors will be second-quarter earnings reports, which are set for release in the next several** weeks. We think that earnings---reflecting the uninspiring state of the economy in the second quarter---will be lower for most companies. A profit recovery of some significance is unlikely before late this year or in 2010.
>
> **The market no longer offers the compelling value that it did several months back**, when the Dow Jones Industrial Average was trading down at about 6,500. Back then, the economy was faltering and equity prices probably were too low. The economy is still in low gear, but stock prices are much higher. That combination increases the overall level of risk in the stock market.

> **Conclusion**: We continue to feel that a cautious approach to equities makes the most sense at this time. Please refer to the inside back cover of Selection & Opinion for our Asset Allocation Model's current reading.

The economic and capital market environment over the last few months has left a lasting impact on investors. However, the impact on the cost of capital depends on the risk profile of the company. While even less risky companies experienced a spike in their cost of capital in the fall of 2008, it appears that much of this fear, at least for companies with stable cash flows, has subsided. However, spreads between lower quality investment grade public utility debt ("Baa" as rated by Moody's, which is the equivalent to a "BBB" credit rating from S&P) and higher quality investment grade public utility debt ("Aa" and "A" as rated by Moody's, which is the equivalent to a "AA" and "A" credit rating from S&P) continue to be higher than they were before the credit crisis (see Schedule 4-6). Generally speaking, it appears that even for higher rated public utility companies there has been a slight increase in the cost of longer-term capital. This is demonstrated by comparing Staff's recommended ROE in the last MGE rate case (8.95% midpoint) to Staff's recommended ROE in this case (9.50% midpoint). However, later in this Report, Staff will provide information from utility company equity analysts that casts doubt as to whether financial analysts that follow utility stocks have increased their required rate of return significantly due to recent economic and capital market events. This leads Staff to believe that investors may have bid the price of utility stocks down more as a result of decreased expected cash flows rather than because of an increase in discount rates (i.e., costs of equity) used to value these cash flows.

D. Overview of Southern Union's Operations, Financing and Staff's Proposed Revised Approach for Estimating MGE's Cost of Capital

The following excerpt from Southern Union's most recent SEC Form 10-Q Filing fairly succinctly explains Southern Union's current business operations:

> Southern Union owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. The Company operates in three reportable segments: Transportation and Storage, Gathering and Processing, and Distribution. The Transportation and Storage segment is primarily engaged in the interstate transportation and storage of natural gas in the Midwest and from the Gulf Coast to Florida, and also provides LNG terminal ling and regasification services. The Gathering and Processing segment is primarily engaged in the gathering, treating, processing and redelivery of natural gas and NGL in West Texas and Southeast New Mexico. The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts.

Southern Union has not been involved in any major mergers and/or acquisitions since MGE's last rate case. However, Southern Union has had an ongoing dispute with one of its major investors, Sandell Asset Management, over the strategic direction of Southern Union and the appropriate corporate structure to create the most value for shareholders. Sandell Asset Management had been pressuring Southern Union to restructure and place the transportation and gathering and processing assets under a Master Limited Partnership (MLP), which is similar to how many other natural gas pipelines are structured. It is not clear from the information Staff reviewed as to how MGE would have been structured under such a reorganization, but it is Staff's understanding that MGE would not have been put under the MLP. Regardless, restructuring of Southern Union has been put on hold per an agreement reached in early 2009 between Southern Union and Sandell Asset Management. Representatives of both entities released statements upon reaching an agreement.

Eric D. Herschmann, President and Chief Operating Officer of Southern Union made the following statement:

> We are pleased that this matter has been resolved in a manner that serves the best interests of all Southern Union stockholders. This agreement will enable Southern Union's management to focus its

> efforts on the Company's operations and avoid a costly and time consuming proxy contest.

Thomas Sandell of Sandell Asset Management made the following statement:

> We are pleased that we were able to work constructively with Southern Union and reach an agreement to avoid a protracted proxy contest. We look forward to working with the Company to maximize value for the benefit of all shareholders. In that regard, we have always believed it is important for Southern Union to maintain its investment grade rating. Therefore, in the current economic environment, we do not believe the Company should undertake extraordinary transactions such as the creation of an MLP, sales of LDC assets or payment of a special dividend or increased dividends.

Because no restructuring took place, there has been no noticeable impact of the previously mentioned activities on Southern Union's capital structure. As can be seen on Schedule 6, Southern Union continues to use a liberal amount of debt. Considering that Southern Union's business risk has increased due to its movement away from being predominately a natural gas distribution company to predominately being a midstream gas company, this leaves little margin for any uncertainty in the future, whether company-specific or general market conditions. Southern Union's current S&P corporate credit rating of "BBB-" is only one notch above "junk" status. The following is an excerpt from an April 21, 2009 Standard and Poors' (S&P) credit rating report on Southern Union:

> The ratings on diversified energy company Southern Union Co. and subsidiary Panhandle Eastern Pipe Line L.P. reflect a strong business profile and aggressive financial profile. Credit strengths include cash flow stability from its transportation and distribution segments, which provide a level of credit support that more than outweighs the amount of cash flow at risk from the gathering and processing segment during times of low commodity prices. Good geographic and asset diversity also enhance Southern Union's credit profile. Furthermore, we believe the recent settlement with Sandell Asset Management Corp. (not rated), Southern Union's largest independent shareholder, removes our concerns that Sandell could implement strategies that we think could hurt bondholders over the next two years. Some commodity risk in Southern Union's

> gathering and processing segment, some execution risk that remains in Southern Union's capital program, and consolidated financial metrics that leave little room for underperformance partially offset these strengths.
>
> We view the transportation and storage segment, and the distribution segment as having excellent business profiles due to supportive regulation that provides Southern Union with a stable base of cash flow. We expect these two segments to provide close to 80% of consolidated EBITDA in 2009. More than 80% of Panhandle's revenue comes from fixed reservation charges, which insulates cash flow from the effects of a decrease in throughput volumes. The company expects its Trunkline LNG enhancement project at its Lake Charles, La. terminal to go into service during the third quarter of 2009. A long-term contract with BG LNG Services LLC (a wholly owned subsidiary of BG Energy Holdings Ltd.; A/Stable/A-1) supports that project. The BG LNG contract will run 20 years from the in-service date…

S&P goes on further to provide the following "Outlook" on Southern Union:

> The stable outlook on Southern Union reflects our belief that the company will successfully execute on its organic growth plans, specifically the completion of its Trunkline LNG infrastructure enhancement project on time and within budget. The rating also reflects our expectation that Southern Union will achieve financial metrics of FFO to total adjusted debt of at least 15% to 16% in 2009 and 2010 and total adjusted debt to EBITDA below 4.5x in 2010. Furthermore, the rating reflects the successful refinancing of the company's short-term credit facility, which in our opinion will allow the company to maintain adequate liquidity through 2009. We could revise the outlook or lower the rating if Southern Union underperforms in any business segment that would result in weaker financial metrics, including FFO to adjusted debt below 14% and total adjusted debt to EBITDA above 5.25x. We also could revise the outlook or lower the rating if the company contemplates share repurchases, or experiences cost overruns at any of its capital projects, including larger-than-anticipated equity contributions to Citrus Corp. for the Phase VIII expansion, as these overruns could increase pressure on the company's financial profile.

Although S&P recognizes that Southern Union's natural gas transportation and storage and natural gas distribution businesses provide the Company with stable cash flow, S&P has concerns about the uncertainty surrounding Southern Union's gathering and processing operations. This concern causes S&P to provide an overall business risk profile of "strong" rather than the "excellent" it assigns to the transportation and storage and distribution operations. Consequently, because Southern Union has not increased its financial risk since it acquired the gathering and processing business, the decreased creditworthiness of Southern Union can be attributed to its increased business risk profile.

Southern Union's lower credit rating should cause higher capital costs for any debt issued subsequent to or near the time of this downgrade. Although Southern Union's embedded cost of debt as of the true-up date (October 31, 2006) in MGE's last rate case included some debt that was issued shortly before the downgrade of Southern Union's credit rating on November 29, 2006, because the overall embedded cost of long-term debt didn't increase, this did not cause Staff concern at the time. However, it is important to continue to consider the cost impact of any other debt that may have been issued by Southern Union since this downgrade.

In the Commission's Report and Order in Case No. GR-2004-0209, the Commission authorized an embedded cost of debt based on debt issuances made directly by Southern Union, not by its Panhandle subsidiary. Consequently, in this audit Staff reviewed all debt issued directly by Southern Union since MGE's last rate case to determine if the costs of these debt issuances were reasonable. According to MGE's response to Staff Data Request No. 0059, the only debt Southern Union issued directly since the last MGE rate case was $100 million of 6.089 percent senior notes issued on February 16, 2008. All other new debt had been issued at its Panhandle subsidiary. However, because Southern Union had retired a total of $225 million of debt since MGE's 2006 rate case, Staff was uncertain as to the source for the remaining $125 million of debt that no longer was on Southern Union's books.

When reviewing Southern Union's 2008 SEC Form 10-K Filing, Staff found a reasonable explanation as to why Southern Union had not issued debt to directly refinance the remaining $125 million of debt. Under the Notes to Southern Union's Financial Statements, Note 13, **Debt Obligations**, the following is indicated: "In August 2008, the Company [Southern Union] repaid and retired its $300 million 4.80% Senior Notes [PEPL debt] and $125 million 6.15% Senior Notes [Southern Union debt] using the remaining proceeds from the 7.00% Senior Notes [PEPL debt] issued in June 2008 and draw downs of its credit facilities." Because proceeds from the 7 percent notes issued by PEPL were used at least in part to retire debt at the Southern Union level, it is evident that Southern Union does not manage the financing of its Panhandle subsidiary separately from its parent company and vice versa. This evidence has prompted Staff to reevaluate the approach it took in MGE's last rate case, which was to use the consolidated capital structure with a cost of long-term debt that excluded debt issued by PEPL.

Based upon this new information, Staff could revert back to the methodology it had originally proposed and the Commission rejected in Case No. GR-2004-0209, which was the application of consolidated embedded costs of debt (i.e. inclusive of PEPL debt) to the consolidated Southern Union capital structure. However, because performing such an approach would require debate on which debt to include in the cost of debt and whether the cost of this debt should be adjusted to consider Southern Union's lower credit rating, Staff believes the parties and the Commission's time would be more efficiently spent debating the proper hypothetical capital structure methodology as well as determining a reasonable allowed ROE for a regulated natural gas distribution utility. However, because of the significance of Staff's decision to change its approach in this case to use of a hypothetical capital structure compared to its previous approach of using the consolidated capital structure, Staff will explain other factors that it considered in making this decision.

In response to Staff Data Request No. 0191, MGE indicated that "The Company [Southern Union] did not raise any specific sources of capital to fund the capital expenditures of its distribution divisions, Missouri Gas Energy and New England Gas Company. Both of the divisions had sufficient internally generated cash flow to fund their construction programs in 2007, 2008 and year-to-date 2009." While this may be true and this is corroborated by the reduction of the amount of long-term debt held at the Southern Union operating company level since the last rate case ($1,379,265,000 as of December 31, 2008, compared to $1,504,265,000 as of October 31, 2006), this does not mean that if these companies had been "stand-alone" natural gas distribution companies, they wouldn't have issued any debt during the past couple of years. Although regulated natural gas distribution companies may generate enough cash from their operations to avoid the need to issue new debt, an optimal financing strategy for most efficiently managed utility companies is to maintain a capital structure that allows it to achieve a low cost of capital. This usually requires utility companies to pay a significant percentage of its earnings out as dividends because it does not have ongoing capital expenditures that require continued retention of cash. Consequently, when the utility company does need financing for capital expenditures, it will still acquire financing by issuing debt and/or if needed, new common equity. If it is assumed that MGE operated as a stand-alone regulated natural gas distribution utility, then it is reasonable to assume that all of its internally generated cash flow would not have been retained, causing the need to periodically issue new debt, which until recently would have lowered the embedded cost of debt because of the very low cost of issuing debt in the recent past. Because of this, Staff believes that continued use of the approach ordered to determine the allowed ROR in MGE's last two rate cases would unfairly require MGE's ratepayers to pay a higher embedded cost of debt in this case.

Another factor that provides support for the use of a hypothetical capital structure and capital costs at this time is the fact that Southern Union's S&P credit rating is currently only one notch above a "junk" credit rating ("BBB-"). Southern Union's corporate credit rating was downgraded from "BBB" to "BBB-" on November 20, 2006, due mainly to Southern Union's higher business risk profile associated with its natural gas gathering and processing operations. Although this factor existed during MGE's last rate case, Staff did not believe that this factor alone justified the movement to the use of a hypothetical approach. It was highly unlikely that this increased risk profile would have an immediate impact on the embedded cost of debt since this cost is based on historical issuances. However, because Southern Union's reduced credit quality due to higher business risk has been in existence for over two years, it is likely that this situation has caused an overall increase in capital costs for Southern Union, and therefore, MGE. In addition, if Southern Union's credit rating is eventually downgraded to "junk" status due to factors other than MGE's regulated natural gas distribution operations, then it would be even more important to ensure that the higher capital costs associated with Southern Union's non-regulated operations are not charged to MGE's ratepayers. In past rate cases involving the former Aquila, Inc. (Aquila) Missouri electric utility operations, Staff recommended adjustments to the cost of debt to ensure the costs of Aquila's non-regulated failures were not charged to ratepayers, but as time elapsed, it became apparent that this estimated cost of debt was very much a matter of judgment rather than being an ideal mechanical calculation used for stable, pure-play regulated utility companies.

E. Determination of the Cost of Capital

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

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

F. Comparable Companies

In order to estimate the cost of capital for MGE, the Staff needed to select an appropriate proxy group. The Staff started with a list of eleven market-traded companies classified as natural gas distribution utility companies by Edward Jones in its June 30, 2009, "Natural Gas Industry Summary" report. (see Schedule 7). This list was reviewed for the following criteria, to develop a proxy group comparable in risk to MGE:

1. Classified as a natural gas distribution company by Edward Jones;

2. Stock publicly traded: this criterion did not eliminate any companies;

3. Information printed in Value Line: this criterion did not eliminate any companies;

4. Ten-year of Value Line historical data available: this criterion did not eliminate any companies;

5. No reduced dividend since 2006: this criterion eliminated one company;

6. Projected growth available from Value Line and IBES: this criterion eliminated three additional companies;

8. At least investment grade credit rating: this criterion did not eliminate any additional companies.

This final group of seven publicly-traded natural gas distribution utility companies (the comparables) was used as a proxy group to estimate the cost of capital for MGE's natural gas distribution utility operations. The comparables are listed on Schedule 8.

G. Capital Structure

As explained earlier in the report, the capital structure Staff used for this case is the proxy group's average capital structure, as of the end of the most recent fiscal quarter available, with the exception of the short-term debt balance, which was based on an average balance for the last four fiscal quarters. The amount of short-term debt was also reduced by each company's CWIP balance, which was based on the balance reported in each comparable company's SEC Form 10-K Filing because of the lack of this detail in the SEC Form 10-Q Filings. Schedule 9 presents the proxy group's average capital structure and associated capital ratios. The resulting capital structure consists of 51.06 percent common stock equity, 40.47 percent long-term debt and 8.47 percent short-term debt. Staff decided to eliminate preferred stock from the proxy group's average capital structure because of the scarcity and inconsistency of its use by the comparable companies.

H. Embedded Cost of Long-Term Debt

Staff determined a recommended embedded cost of debt by calculating each comparable company's overall weighted average cost of long-term debt. Staff's methodology for the cost of long-term debt closely follows that in the Direct Testimony of Company witness Hanley. Staff used information provided in each comparable company's SEC Form 10-K Filing and then updated this information through each company's most recently reported fiscal quarter. Staff then calculated a simple average of the proxy group's cost of long-term debt in order to assign equal weight to each company's cost of debt. Staff's final stated cost of debt estimate was 5.82 percent.

Because the proxy group's cost of long-term debt information was based only on stated interest rates provided for each debt issuance, this cost of debt does not reflect issuance expenses that are normally reflected in a company-specific cost of debt calculation. Because of the lack of this information, Staff based its estimate of issuance costs (10 basis points) on The Laclede Gas Company's issuance costs in its last rate case, Case No. GR-2007-0208. Staff's final embedded cost of long-term debt recommendation is 5.92 percent.

Staff's final cost of long-term debt recommendation is shown on Schedule 10. The supporting calculations for each company's cost of long-term debt are shown in the schedules that immediately follow this schedule.

I. Cost of Short-term Debt

Ideally, Staff would recommend the use of an average cost of short-term debt for all of the companies in its proxy group because it is important to match the costs of the capital components with their weights in the capital structure. However, for practical reasons, Staff was unable to do so. Staff could not find enough detail in the most recent SEC Form 10-Q Filing for each comparable company to determine an average cost of short-term debt for all the companies. Because Staff's comparable companies have credit ratings that range from "BBB+" to "AA-", with an average of an "A" credit rating, Staff believed a fair and reasonable approach was to use the comparable companies that had a credit rating equivalent to the average credit rating of the comparable group (assuming the data was available for these companies). Fortunately, these two companies (Piedmont Natural Gas Company and New Jersey Resources Company) had weighted average cost of short-term debt information available in their most recent SEC Form 10-Q Filings.

Because short-term rates have been quite low during the last few months, the weighted average cost of short-term debt for these two companies has also been low. The simple average of each of these company's weighted average cost of short-term debt was 0.89 percent as of each company's most recently reported fiscal quarter ((1.05% + 0.72%)/2). This is the cost of short-term debt Staff used for its recommended rate of return.

J. Cost of Common Equity

In order to estimate the cost of common equity for MGE, the Staff performed a cost of common equity analysis on the seven comparable companies. The Staff estimated MGE's cost of common equity using the constant-growth DCF (explained in detail in Attachment A) and the CAPM (explained in detail in Attachment B). Staff then reviewed other indicators to test the veracity and practicality of its recommendation. Staff will discuss these in more detail later in this segment of the report.

The Staff decided to rely primarily on its traditional constant-growth DCF analysis in this case rather than the multi-stage DCF analysis it performed in the recent Kansas City Power & Light Company (KCPL) and KCPL – Greater Missouri Operations (GMO) rate cases (Case Nos. ER-2009-0089 and ER-2009-0090, respectively). Although economic conditions still cause Staff concern about the sustainability of certain growth rate estimates, because historical and projected growth rates of the natural gas utility industry have been fairly consistent, Staff has less concern about the reliability of the constant-growth DCF when applied to the natural gas distribution industry rather than the electric utility industry.

Because of the dramatic events in the economy and the market over the last few months, risk premiums have generally increased, but this is also due in large part to the decrease in risk-free rates. The amount that can be explained by the change in risk-free rates or increased risk-aversion depends on the perceived safety or lack thereof of any given investment.

It is also important to understand that risk premiums have increased because investors are more pessimistic and uncertain about the future growth of the domestic economy. Based on projections made by the Federal Reserve, the long-term real growth in the economy is expected to be 2.5 to 2.7 percent.[7]

It is debatable how much of an impact economic and business cycles have on the long-term growth rates of natural gas distribution companies. Under MGE's current straight-fixed variable (SFV) rate design for the residential class, growth in earnings for this class would be driven entirely by customer growth. Therefore, at least for the residential class, if the contraction in the economy causes vacant housing, then this will cause a reduction in earnings from residential customers. It is Staff's understanding that MGE has experienced a

[7] Minutes of the Federal Open Market Committee, June 23-24, 2009, http://www.federalreserve.gov/monetarypolicy/fomccalendars.htm

contraction in the number of residential customers specifically, as well as in its total number of customers. At least for the customers that are billed based on a SFV rate design, this translates into a direct loss of margin and, therefore, a decline in cash flow to shareholders, assuming rates are held constant.

Ideally, in estimating the cost of common equity for MGE, one would seek to find publicly-traded natural gas distribution companies that have these same characteristics. Unfortunately, there are no publicly-traded natural gas distribution companies that are completely confined to regulated natural gas distribution operations with the exact same characteristics as MGE. All of the publicly-traded natural gas distribution companies available for estimating the cost of equity have varying economic conditions and rate designs that affect their growth and risk profile. Although Staff's comparable companies have rate designs that are similar in nature to MGE's for their regulated natural gas distribution operations, these companies also have varying amounts of non-regulated operations that affect their aggregate growth and risk profile. Regardless, Staff believes its proxy groups' risk characteristics are reasonably consistent with natural gas distribution operations and can at least be used as a starting point for estimating a fair and reasonable return on common equity.

Staff is not aware of any specific studies performed on the natural gas distribution industry that address the potential impacts of a low-growth economy on expected growth for natural gas distribution companies. The reason utility companies in general are considered to be safe investments is because the demand for utility services is not expected to be as sensitive to economic cycles as other less essential goods and services. However, it is only logical to conclude that the growth, or lack thereof, of the real estate market would be a primary driver of earnings growth for a utility company. In fact, during the recent KCPL rate case, Case No.

ER-2009-0089, Staff cited GPE's concerns about the impact that the contraction in the regional economy would have on the demand for its services. Because MGE provides natural gas utility service in many of the same areas, to the extent that this causes slowing in the real estate market, this will impact MGE's potential for growth also. While some may argue that this is a risk factor which would require a higher rate of return, it also means that investors would expect very low growth or even negative growth in cash flows from this investment. It is important to understand these fundamental concepts when judging the reasonableness of an estimated cost of common equity.

The first step Staff performed in its constant-growth DCF analysis was to estimate a growth rate. The Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected DPS, EPS and BVPS growth rates for the comparables. Schedule 11-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 11-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 11-3 presents the averages of the growth rates shown in Schedules 11-1 and 11-2.

Staff also analyzed the projected DPS, EPS and BVPS as estimated by the Value Line analyst over the next five years for each company (see Schedule 12). The average of these projected growth rates was lower than the average of the five and ten-year historical averages. When comparing the EPS estimates from Value Line to equity analysts' EPS estimates from IBES, Staff discovered a difference of over 100 basis points, with the IBES estimates being higher (see Schedule 13).

The next step was to calculate an expected yield for each of the comparables. The yield term of the constant-growth DCF was calculated by dividing the amount of DPS expected to be paid over the next 12 months by the market price per share of the firm's stock.

Staff decided to use an average of the 2009 and 2010 projected DPS from Value Line to approximate investors' expected dividends over the next 12 months. This is a reasonable proxy because if investors purchase any one of these stocks, this would be the amount of dividends they could reasonably expect to receive.

It is important to ensure the selection of stock prices that reflect investors' current expectations of the business and economic climate. Staff believes the use of stock prices for the three months through the end of June 2009 is reasonable as this reflects investors' analysis of the current economic conditions over the most recent quarter and the impact it is having on their expectations of future returns and the risk of these returns. It should be noted that Staff's use of three months of average stock prices for the comparable group is different from its past practice of using four months of stock prices. Staff decided to make this change because most financial data is reported at least on a quarterly basis.

The monthly high/low averaging technique minimizes the effects on the dividend yield which can occur due to short-term volatility in the stock market. Schedule 14 presents the average high / low stock price for the period of April 1, 2009, through June 30, 2009, for each comparable.

Column 1 of Schedule 15 indicates the expected dividend for each comparable over the next 12 months as projected in the most recent Value Line report. Column 3 of Schedule 15 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected average dividend yield for the comparables of 4.50 percent. Considering the Commission's position regarding the quarterly-compounding of dividends expressed in its Report and Order in the most recent Union Electric rate case, Case No. ER-2008-0318, it is important to note that this dividend yield has not been adjusted for quarterly compounding. Staff is attempting to estimate investors' expectations and because the Value Line quoted dividend yield does not reflect quarterly compounding, Staff is not convinced that investors' analyze the expected dividend yield on a quarterly-compounded basis.

As shown on Schedule 15, Staff's estimate of the proxy group's cost of common equity based on the projected dividend yield and a growth rate range of 4.75 to 5.75 percent is 9.25 percent to 10.25 percent.

MGE is a pure-play regulated natural gas distribution utility with a rate design that provides more stability in MGE's cash flows. Although Staff's comparable companies also have varying decoupled rate designs, Staff's comparable companies all have at least some degree of non-regulated operations that affect the growth and risk profile of these companies. For this reason, Staff recommends that the lower half of Staff's estimate proxy group cost of common equity range be used to estimate MGE's cost of common equity. Consequently, Staff's recommended cost of common equity range is 9.25 percent to 9.75 percent with a mid-point of 9.50 percent.

In further support for Staff's decision to recommend the lower end of its range, Staff discovered a June 27, 2008 Goldman Sachs equity research report on Atmos Energy Corp. which stated, "Decoupling a positive, even at a lower RoE; maintain Neutral." This demonstrates that at least the Goldman Sachs' investment analyst believes obtaining a decoupled rate design is worth accepting a lower authorized ROE (9.60% compared to 10.0% previously) for purposes of creating shareholder value.

The Staff also performed a CAPM cost of common equity analysis on the comparables. The CAPM requires estimates of three main inputs, the risk-free rate, the beta and the market risk premium. For purposes of this analysis, the risk-free rate Staff used was the yield on Thirty-year U.S. Treasury Bonds. The Staff determined the appropriate rate to be the average yield for July 2009. The average yield of 4.41 percent was obtained from the St. Louis Federal Reserve website.

For the second variable, beta, the Staff used Value Line's betas for the comparable group of companies. Schedule 16 contains the appropriate betas for the comparables.

The final term of the CAPM is the market risk premium (R_m - R_f). The market risk premium represents the expected return from holding the entire market portfolio, less the expected return from holding a risk-free investment. The Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds. However, just as the Staff warned against using these risk premiums when Staff thought they were too high because of low implied equity risk premiums, Staff believes that these risk premium estimates may still be too low when applied to lower risk-free rates. Consequently, the reliability of cost of common equity results obtained from performing a CAPM analysis or risk premium analysis is heavily dependent on the estimated risk premium used to determine the cost of common equity.

Estimated risk premiums based on earned return spreads through 2008 have declined significantly since the previous year. The geometric risk premium estimate declined by 100 basis points and the arithmetic risk premium estimate declined by 90 basis points. Staff believes this validates its practice of using the CAPM as only a test of reasonableness of its DCF estimated cost of common equity. It is counterintuitive to use a lower equity risk premium as an input into the CAPM if the broader stock market had declined due to investors' increased risk-aversion due to concerns about the economy. If the inputs in the CAPM analysis are not adjusted to reflect the current capital and economic environment, then the CAPM will yield unreliable results. Because the estimation of implied equity risk premiums is often done by using some variation of the DCF model, Staff believes any such attempt in this case to estimate the equity risk premium for purposes of using the CAPM model will only be as reliable as the DCF analysis used to estimate this equity risk premium. If the DCF analysis doesn't appear to be reliable, then any risk premiums estimated using a DCF analysis will be unreliable. Consequently, Staff continues to believe the best approach for estimating a utility company's cost of common equity is through a DCF analysis. Nevertheless, Staff performed a CAPM analysis to show the impact that recent capital market and economic events have had on CAPM results using the historical earned return risk premiums using both arithmetic and geometric averages.

The first risk premium the Staff used was based on the long-term, arithmetic average of historical return differences from 1926 to 2008, which was 5.60 percent. The second risk premium used was based on the long-term, geometric average of historical return differences from 1926 to 2008, which was 3.90 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2009 Yearbook.*

Schedule 16 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the long-term arithmetic average risk premium and the long-term geometric average risk premium produces estimated costs of common equity of 8.09 percent and 6.97 percent respectively. Although Staff does not believe these current CAPM results should be used to estimate MGE's cost of common equity, they do illustrate the impact of the stock market declines that occurred in 2008 on CAPM analyses using historical earned return risk premium differences.

Staff has reviewed a variety of sources to test the reasonableness of the inputs it used in its DCF analysis and the reasonableness of its cost of common equity estimate. Staff also reviewed other data to test the reasonableness of its estimated cost of common equity for purposes of recommending a fair ROE to allow on MGE's rate base.

In order to test the reasonableness of the Staff's estimated cost of common equity, Staff reviewed several equity research reports published on each of Staff's comparable companies. These research reports were published by a variety of financial institutions that follow these companies (Brean Murray Carret & Co., Citigroup Global Markets and The Goldman Sachs Group, Inc.). While Brean Murray Carret & Co. ("Brean Murray") was the most consistent in providing equity discount rates (i.e. costs of common equity) in its reports for each of the comparable companies, Citigroup Global Markets ("Citigroup") and The Goldman Sachs Group, Inc. ("Goldman Sachs") also provided corroborating lower equity discount rates for AGL and Atmos. Staff discovered equity discount rates in these reports that ranged from as low as 7.30 percent to no higher than 8.50 percent (see Schedules 20-1 through 20-7).

Staff also discovered that Brean Murray did not use a constant-growth rate any higher than 5.50 percent for any of the comparable companies when performing a single-stage Dividend Discount Model (DDM) analysis, which is the same as the DCF model in utility regulatory terminology. Additionally, although Staff did not perform a multiple-stage DCF analysis in this case, another "reasonableness check" on investors' expectations of sustainable growth rates is illustrated by the fact that Goldman Sachs used terminal growth rates of only 2 percent when discounting dividends in its DDM analysis.

It is also informative to notice that the costs of equity used by the aforementioned investment advisors to discount cash flows after the credit collapse in the fall of 2008 did not increase more than 55 basis points and in some cases, they even decreased. This demonstrates to Staff that at least according to investment analysts, the comparable companies' stock prices declined more as a result of pessimism about expected cash flows rather than because of investors requiring a much higher return for these cash flows.

The information Staff found on equity discount rates used by investment analysts for discounting cash flows for the natural gas utility industry was not surprising. In the recent KCPL and GMO rate cases, Staff discovered that investment analysts used fairly low equity discount rates to discount expected cash flows for regulated electric utility companies. If anything, Staff expected to discover the use of even lower equity discount rates for the regulated natural gas utility industry because of its movement towards rate designs that allow for more stability in cash flow due to the recovery of non-commodity costs not being dependent on usage.

In order to further test the reasonableness of Staff's estimated cost of common equity for MGE's operations, Staff contacted the Missouri State Employees' Retirement System (MOSER's) to acquire specific information about MOSER's expectations for returns for a variety of asset classes. According to the information Staff reviewed, MOSER's expected returns for large capitalization domestic equities is only 8.50 percent. Because regulated natural gas utility companies exhibit less risk than the broader market (as measured by betas), this demonstrates the conservativeness of my recommended cost of common equity for MGE of 9.25 to 9.75 percent, which is above what MOSER's expects for the broader markets.

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

According to RRA, the average authorized ROE for gas utility companies for the first six months of 2009 was 10.15 percent based on 12 decisions (first quarter – 10.24 percent based on four decisions; second quarter – 10.11 percent based on eight decisions).

The average authorized ROE for gas utility companies for 2008 was 10.37 percent based on 30 decisions (first quarter – 10.38 percent based on seven decisions; second quarter – 10.17 percent based on three decisions; third quarter – 10.49 percent based on seven decisions; fourth quarter – 10.34 percent based on thirteen decisions).

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

The average authorized ROR for gas utilities for the first six months of 2009 was 8.05 percent based on eleven decisions (first quarter – 8.01 percent based on five decisions; second quarter – 8.08 percent based on six decisions).

The average authorized ROR for gas utilities in 2008 was 8.48 percent based on thirty decisions (first quarter – 8.78 percent based on seven decisions; second quarter – 8.28 percent based on three decisions; third quarter – 8.33 percent based on seven decisions; fourth quarter – 8.45 percent based on thirteen decisions).

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

K. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.19 percent to 7.45 percent was developed for MGE's natural gas distribution operations (see Schedule 19). This rate was calculated by applying an embedded cost of long-term debt of 5.92 percent and a cost of common equity range of 9.25 percent to 9.75 percent to a capital structure consisting of 51.06 percent common equity, 40.47 percent long-term debt and 8.47 percent short-term debt. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that MGE's natural gas distribution operations be allowed to earn a return on its rate base in the range of 7.19 percent to 7.45 percent.

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

Staff Expert: David Murray

VI. Rate Base

A. Plant in Service and Depreciation Reserve

Plant in Service (Plant) and Accumulated Depreciation Reserve (Depreciation Reserve) are two of the largest components of Rate Base. Plant represents the structures and equipment used by the utility to provide service to ratepayers. In the balance sheet, plant is often referred to as "fixed assets." The depreciation reserve represents the sum of all depreciation accruals, net of cost of removal and salvage charges that have been recorded against plant placed in service. The reserve is a subtraction from plant in the determination of rate base, and the resulting balance is known as "net plant."

Accounting Schedule 3, Plant in Service and Accounting Schedule 6, Depreciation Reserve, respectively, reflect MGE's balances by account for these items as of April 30, 2009, the end of the test year update period in this proceeding. These schedules include plant additions that have occurred since the end of the December 31, 2008 test year, and all depreciation reserve accruals that have been booked by MGE through April 30, 2009.

Accounting Schedule 4, Adjustments to Total Plant, details the Staff's individual adjustments to the total plant in service. The Staff is proposing a plant adjustment in this case is to remove certain "inactive" services from the plant accounts. This adjustment has been proposed by both the Company and the Staff in MGE's last several rate proceedings. Other adjustments to plant and reserve for switching fleet from lease to purchase will be discussed by Staff witness Amanda McMellen in the Lease Expense section of the Cost of Service Report.

Accounting Schedule 7, Adjustments to Depreciation Reserve, details the Staff's individual adjustments making up the total company and Missouri jurisdictional adjustments to

Accounting Schedule 6. An adjustment to remove the impact of inactive services will also be made to the depreciation reserve. The only other Staff adjustment to the depreciation reserve will be the application of Commission approved depreciation rates to MGE's corporate plant accounts, as well as the aforementioned lease to purchase adjustments. The need for the corporate plant reserve adjustment is discussed in the Corporate Allocations section of the Cost of Service Report.

Staff Expert: Bret G. Prenger

B. Cash Working Capital

Cash Working Capital ("CWC") is the amount of funding necessary for a utility to pay the day-to-day expenses incurred in providing utility services to its customers. When a utility expends funds in order to pay an expense necessary to the provision of service before its customers provide any corresponding payment, the utility's shareholders are the source of the funds. This shareholder funding represents a portion of each shareholders' total investment in the utility, for which the shareholders are compensated by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the CWC-related funding they have invested.

Customers supply CWC when they pay for electric services received before the utility pays expenses incurred in providing that service. Utility customers are compensated for the CWC they provide by a reduction to the utility's rate base. By removing these funds from rate base, the utility earns no return on that funding which was supplied by customers as CWC.

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

As will be demonstrated below, the results of the study performed by Staff resulted in a positive CWC requirement. This means that in the aggregate MGE's shareholders have provided the CWC to the Company during the test year. Therefore, it is Staff's recommendation that the shareholders should be compensated for the CWC that they provide, through an increase in the Company's rate base.

The components of the Staff's CWC calculation found on Accounting Schedule 8 on the EMS run are as follows:

1) Column A (Account Description): lists the types of cash expenses, which MGE pays on a day to day basis.

2) Column B (Test Year Expenses): provides the amount of annualized expense included in MGE's cost of service. Column B basis the dollars associated with those items on an adjusted jurisdictional basis in Column A.

3) Column C (Revenue Lag): indicates the number of days between the midpoint of the provision of service by MGE and the payment by the ratepayer for such service. Further explanation of the Revenue Lag can be found later in this Report.

4) Column D (Expense Lag): indicates the number of days between the receipt of and payment for the goods and services (i.e., cash expenditures) used to provide service to the ratepayer. Further explanation of the Expense Lag can be found later in this Report.

5) Column E (Net Lag): results from the subtraction of the Expense Lag (Column D) from the Revenue Lag (Column C).

6) Column F (Factor): expresses the CWC lag in days as a fraction of the total days in the test year. This is accomplished by dividing the Net Lags in Column E by 365.

7) Column G is the CWC Requirement needed for each expense listed. The amounts in this Column are calculated by multiplying the test year/annualized balances with the CWC Factor (Column F).

The result of Staff's CWC analysis is reflected on the Cash Working Capital Schedule 8. Staff's CWC analysis result is also reflected on the Rate Base Accounting Schedule 2 in the section entitled "Add to Net Plant In Service." Other aspects of Staff's CWC analysis results are also listed in the Rate Base Schedule in the section entitled "Subtract From Net Plant": Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset. The need for separation of the Staff's recommended CWC allowance into different rate base components is explained later in this Report.

Revenue Lag (Column C) - The revenue lag is the amount of time between the day the Company provides the utility service, and the day it receives payment from the ratepayers for that service. The Staff's overall revenue lag in this case is the sum of three (3) subcomponents. They are as follows:

1) Usage Lag: The midpoint of average time elapsed from the beginning of the first day of a service period through the last day of that service period;

2) Billing Lag: The period of time between the last day of the service period and the day the bill for that service period is placed in the mail by the Company; and

3) Collection Lag: The period of time between the day the bill is placed in the mail by the Company and the day the Company receives payment from the ratepayer for the services provided.

	Staff
Usage Lag	15.21
Billing Lag	3.83
Collection Lag	21.41
Payment Lag	0
Total Revenue Lag	**40.45**

The usage lag was determined by dividing the number of days in a typical year (365) by the number of months in a year (12) to yield the average number of days in a month (30.42). The 30.42 was then divided by two (2) to yield an average usage lag of 15.21 days. This further calculation using two (2) as the divisor is necessary since the Company bills monthly, and it is assumed that service is delivered to the customer evenly throughout the month.

The billing lag is the time it takes between when the Company reads the meter and when the bills are subsequently mailed to customers. Staff completed a lead lag study in order to determine the appropriate billing lag. According to Mr. Robert O'Brien, a Company consultant employed in this proceeding, the Company's billing lag was calculated at 4.37 days. Staff found, upon review of Mr. O'Brien's workpapers, that Mr. O'Brien calculated the billing lag beginning with the meter read date and ending with the bill date. As a result, the mailing date was not factored into his calculations which, if reflected, would have reduced MGE's billing lag by approximately one (1) day. To determine the duration of MGE's current billing lag, the Staff reviewed MGE's billing lag analysis presented as part of this case. Under the Staff's traditional methodology, the billing lag should be calculated starting with the meter read date and ending with the mailing date. Using this definition, the Company's workpapers showed that the Company's actual billing lag is 5.83 days.

However, Staff believes that both the MGE's current billing lag calculated by Mr. O'Brien and the actual billing lag initially calculated by Staff are excessive. While researching data from previous rate cases filed between 1997 and 2009, Staff found that on average, Missouri jurisdictional utilities filed less than 4 days for their billing lags. Considering only cases filed within the past five years, Staff found that Missouri jurisdictional utilities sponsored an average billing lag of 3.42 days during this period, and Staff recommended an average 2.74 days billing lag in those cases.

Based on discussions with the Company and upon Company responses to Staff Data Requests, MGE believes that its current 5-6 day billing lag is necessary to insure the accuracy and the integrity of the Company's billing process. The Company's initial billing process lasts for three (3) business days, which consists of meter reading and pre-bill process, beginning with the day the meters are read and ending on the day before billing. The Company then allows one (1) additional day for billing and one (1) day for mailing, thus creating an approximate five (5) day billing window. Staff is recommending a reduction to the Company billing lag, based on the research indicating that Missouri utilities average a billing lag of less than four (4) days. Staff recommends reducing its initial calculation of 5.83 days by two (2) days, or 3.83 days. This is in line with the average billing lag achieved by other major Missouri jurisdictional utilities in recent years.

The collection lag is the average number of days that elapse between the day the bill is mailed and the day the Company receives payment for that bill. Staff determined the collection lag period by using a accounts receivable turnover calculation; comparing a thirteen (13) month average of MGE's Account Receivable ending monthly balances for the test year ending December 31, 2008 to the total sales recorded by the Company in the same time period. The result of this calculation is the average time that customer payments due to the utility are included in its accounts receivables balance, a duration that approximates the Company's collection lag. However, a utility's accounts receivable balance at any point will include some customer billings that will later be determined to be uncollectible, or "bad debts." Bad debts are a non-cash expense item and should not be included in a CWC analysis. Accordingly, the Staff removed a reasonable estimate of the amounts embedded within MGE's monthly accounts receivable balances that were later written off as uncollectible by the Company. After this adjustment for bad debts, the Staff's calculated collection lag was quantified to be 21.41 days.

The Staff's revenue lag calculation is based upon the time lapse between the point on average between when a customer receives service from MGE and when MGE receives the customer payment for that service in the mail. The sum of the Staff's usage, billing and collection lags for MGE in this proceeding is 40.45 day. The Staff opposes any effort to incorporate a measurement of "bank float" or any similar measurement of electronic receipt of funds in the revenue lag calculation.

Expense Lag (Column D)

An extensive lead lag study for expense lags was performed by Staff in MGE's last rate case, Case No. GR-2006-0422. In the current case, Staff has reviewed the expense lag calculations made by Staff in Case No. GR-2006-0422 as well as the calculations sponsored by the Company witness Robert L. O'Brien in this case. For some expense lags Staff decided to perform a new expense lag study for this case. The following CWC expense lags were accepted as reasonable from Staff's calculations in Case No. 2006-0422: Cash Vouchers, Property Taxes and Corporate Franchise Taxes.

The cash vouchers line item is designed to include all operation and maintenance (O&M) expenses within the study that are not specifically analyzed in a separate line item. The expense lag represents the amount of time elapsed between the receipt of and payment for goods and services necessary to provide service to ratepayers. The cash vouchers lag utilized by Staff is 30.30 days and is located on Line 10 of Accounting Schedule 8.

Property taxes are paid by the Company on assessments made by the taxing authority on property that has been placed in service by January 1st of each year. For purposes of Staff's Cash Working Capital analysis, the property tax lag days are calculated by using the midpoint of the service period (a calendar year) and the required due date for property taxes paid by MGE. The property tax lag utilized by Staff is 182 days and is located on Line 13 of Accounting Schedule 8.

Corporation franchise taxes are paid annually. The expense lag considers the time elapsed between the midpoint of the taxable period (a calendar year) and the statutory due date (April 15 of the current fiscal year). The corporation franchise tax lag utilized by Staff is (77.00) days. The franchise tax lag is on Line 14 of Accounting Schedule 8.

Staff performed a lead/lag study on the following expense lags during the audit: Payroll and Employee Withholdings, Vacation, Pensions, Benefits, Gas Purchases, Employee FICA Taxes, Federal and State Unemployment Taxes, Use Tax, Sales Tax, Gross Receipt Taxes, Federal and State Income Tax and Interest Expense.

The payroll and employee withholdings is an expense lag representing the time elapsed between the midpoint period in which the employees earn wages and the dates on which the wages are paid. In this case the Company pays its employees on a bi-weekly basis. The pay period ends on a Saturday and the employees are paid on the following Friday resulting in a 13-day payroll expense lag. However, effective August 17, 2007, MGE entered an agreement with ADP Inc. to handle MGE's payroll. The payroll administrator requires MGE to submit cash to the administrator on Wednesday, two days prior to payment being made to the employees. As a result the initial payment lag of 13 days is reduced by two days. Therefore, the payroll expense lag calculated by Staff is 11.00 days and is located on Line 2 of Accounting Schedule 8.

The vacation expense lag attempts to reflect the time period from when employees "earn" vacations and when MGE actually pays out the cash to these employees for time spent on vacation. Pending additional information from the Company, Staff utilized a vacation lag of 182.5 for union and non-union employees. The vacation lag is based on changes made to the Company vacation policies effective 1/1/2008. The changes made support the Staff's belief that the Company accrues and expenses vacation within a one year period. However, as mentioned above, this lag is subject to change pending additional information from the Company. The vacation lag is located on Line 3 of Accounting Schedule 8.

The expense lag for pensions is the time elapsed between the midpoint of the period of service and the date on which payments were made. Staff used the period from January 2008 to December 2008 to calculate this expense lag. The following chart indicates the service dates for 2008 in addition to its corresponding pension payment date and payment amount:

Service Provider	Service Start	Service End	Payment Date	Payment Amount
Bank One and JP Morgan	1/1/2008	12/31/2008	4/15/2008	3,300,000.00
Bank One and JP Morgan	1/1/2008	12/31/2008	7/15/2008	3,300,000.00
Bank One and JP Morgan	1/1/2008	12/31/2008	10/15/2008	3,300,000.00
Bank One and JP Morgan	1/1/2008	12/31/2008	1/15/2009	3,300,000.00

Staff recommends a pension lag of 59.75 days. The lag is located on Line 5 of Accounting Schedule 8.

The benefits lag represents the health and dental claims, group health and dental administration, pensions, and life insurance (which include accidental death and dismemberment, and long term disability coverage). The expense lag for benefits is the time elapsed between the midpoint of the period of service and the date on which payments were made. Staff used the period from January 2008 to December 2008 to calculate this expense lag. As a result the benefits lag is 33.64 days and can be found on Lines 6 of Accounting Schedule 8.

The expense lag for gas purchases is the time between the midpoint of the period when the Company receives the gas from the suppliers and the date payments are made by the Company. The gas purchases expense lag is 38.55 days and can be found on Line 7 of Accounting Schedule 8.

The expense lag for employee FICA taxes is calculated by using the same method as payroll expense. The expense lag is 11.00 days and can be found on Line 15 of Accounting Schedule 8.

Federal and State unemployment taxes are quarterly taxes due by the 15th of the month following the end of the quarter. The expense lag for Federal and State unemployment is 60.25 days and can be found on Line 16 of Account Schedule 8.

The expense lag for the use tax is calculated using the midpoint of the period date and the date payment is made by MGE. This tax is billed and paid on a quarterly basis. The use tax expense lag is 41.80 days and can be found on Line 17 of Accounting Schedule 8.

The expense lag for sales tax is calculated using the midpoint of the period date and the date payment was made by MGE. Unlike the use tax, sales tax is billed on a monthly basis and paid the following month. The expense lag is 12.49 days and is located on Line 18 of Accounting Schedule 8.

MGE pays gross receipt taxes (commonly referred to as franchise taxes) for the right to do business in the municipalities in which they operate. Gross receipts taxes are prepaid by customers to the utility, which then have the use of these funds for a period of time prior to turning these amounts over to the municipal taxing authorities. The gross receipts tax is calculated based on a percentage of total revenues. This tax is listed on the ratepayer's statement as a separate line item. Staff found that the tax amount 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. Staff calculated the time period from when MGE collects funds from the customers to the time it remits payment to the taxing authorities. As a result, the gross receipts tax expense is 21.20 days and is located on Line 19 of Accounting Schedule 8.

The Company is required to collect taxes for municipalities in which they operate. The three taxes previously mentioned, gross receipts tax, use tax and sales tax, are included as separate line items on the ratepayer's bill. However, when the funds are received, the Company remits payments to the taxing authority based on the arrangement established with the taxing authority. Since the Company collects the taxes for the taxing authority and a service is not provided to the ratepayer by the Company, measurement of the revenue and expense lags calculations start with the beginning point of the collection lag for these taxes. The collection lag was defined earlier in this report as the period of time between the day the bill is placed in the mail by the Company and the day the Company receives payment from the ratepayer for the services provided. As a result of using this methodology, the gross receipts tax, sales tax and use tax CWC line items have a shortened revenue and expense lag.

The Federal and State income tax line items represent the period of time between the midpoint of the taxable period (a calendar year) and the required dates taxes are due to the federal and state taxing authorities. Currently, 100% of the estimated federal tax must be paid during the year in four (4) quarterly installments, which are due by the 15th day of April, July, October and the following January. The same due dates apply to state income taxes. The expense lag for Federal and State income taxes is 60.25.

The interest expense lag is computed by determining the time elapsed between the midpoint of the interest period and the required due date for the payment of interest on long-term debt. The interest expense lag is 81.25 days.

The federal income tax offset, state income tax offset and interest expense offset line items do not directly appear in the Accounting Schedule 8, Cash Working Capital. These items appear as separate line items in the Staff's Accounting Schedule 2, Rate Base. These cash payments are known and certain obligations of MGE with payment periods and payment dates established by statute or bond indentures. The Staff believes amounts collected from ratepayers, which the Company intends to use for the payment of taxes and interest, represent a source of cash for MGE. The Company has use of such funds until they are passed on to the appropriate taxing authority or bondholder. The Staff believes it is appropriate to include taxes and interest as offsets in a lead/lag analysis. The expense component used for these offsets is tied directly to the mechanical computation of the revenue requirement. The Staff's computer-generated revenue requirement is based on a computer program with the capability of extracting appropriate amounts for federal income tax, state income tax and interest expense based on amounts obtained from Accounting Schedule 11, Income Tax. The computer program applies the CWC factor for each respective component and places the CWC revenue requirement directly in Accounting Schedule 2.

All of the Staff's expense lag calculations are measured to the point in which the Company makes payment for the goods and services received. The Staff opposed efforts to incorporate "bank float" or similar electronic measurements of when funds are actually removed from the Company's bank accounts in expense lag calculations.

In conclusion, the results of the study performed by Staff resulted in a positive CWC requirement. This means that in the aggregate the shareholders have provided the CWC to the Company during the test year. Therefore, the shareholders should be compensated for the CWC that they provide, through an increase to rate base.

Staff Expert: Karen K. Herrington

C. Stored Gas Inventory

Natural gas is purchased and injected into storage facilities during the summer months where it is held until the winter months when it is withdrawn and delivered to MGE's distribution system. This natural gas stored underground represents an investment by MGE. Therefore, it is included in rate base which allows the Company an opportunity to earn a return on its investment. Currently MGE has storage agreements with two interstate pipelines, Southern Star Central and Panhandle Eastern Pipe Line. The Staff included in rate base a 13-month average of the combined inventory quantities and corresponding prices for gas storage inventory levels from April 2008 to April 2009. Natural gas inventory is cyclical in nature. Inventory volumes increase throughout the summer as gas is injected into storage and then decrease throughout the winter as gas is withdrawn. An average is used to account for the fluctuation in inventory levels over time.

Staff Expert: Amanda C. McMellen

D. Prepayments and Materials and Supplies

Prepayments are the costs a company incurs and pays in advance. MGE has utilized its own funds for prepaid items such as insurance premiums and postage. The Staff examined MGE's prepayment account balances over the last several years on a month-by-month basis. Based on this review and the variability in the monthly account balances, the Staff determined the prepayment levels to include in MGE's rate base by calculating the 13-month average level as of April 30, 2009, the end of the update period. The Staff used this approach because there was no discernable upward or downward trend in the monthly balances. The Company also holds an inventory of materials and supplies necessary in performing its utility operations. The Staff reviewed the monthly balances for materials and supplies over the last several years because the account balances fluctuated from month to month with no distinguishable trend and the Staff determined that a 13-month average was also appropriate as of April 30, 2009

Staff Expert: Amanda C. McMellen

E. Prepaid Pension Asset/Pension Tracker Asset/Liability

Statement of Financial Accounting Standards (FAS) No. 87 provides the Generally Accepted Accounting Principles (GAAP) method used for recognizing the annual pension cost liability for financial reporting purposes for business entities. The ERISA regulations discussed in the Pension Expense section of the COS Report address funding requirements for the same pension plan liability. Annual differences between FAS 87 expense amounts and minimum ERISA funding requirements occur because the actuarial methods used to assign cost differently over the service lives of employees. Annual differences between pension cost under FAS 87 for financial reporting and cash contributions to the fund are accounted for as either a prepaid pension asset (cash contribution exceeds FAS 87 accrual) or an accrued liability (FAS 87 accrual exceeds cash contribution).

For major utility companies in Missouri, the existence of prepaid pension assets has resulted primarily from negative pension expense amounts calculated under FAS 87 that were previously used to set rates in this jurisdiction, compared to zero minimum ERISA contribution levels experienced by utilities in the 1990s and early years of this decade. A negative pension expense reduced cash flow to the utility. The excess of fund assets over the pension liability in prior years could not be withdrawn and used to offset the negative cash flow that resulted from reflecting a negative pension cost under FAS 87 in setting rates. The prepaid pension asset, in effect, represents a cash flow benefit (reduction in rates), which, in theory, should reverse over the service life of the employees used to accrue pension cost for financial reporting purposes. In other words, there should not be any permanent difference between the recognition of the pension liability for financial reporting over the service life of employees and the funding of the same liability over the long term.

Since a Stipulation and Agreement approved in Case No. GR-2004-0209 changed the method used to determine MGE's pension expense for ratemaking purposes from FAS 87 to the minimum ERISA approach, the prepaid pension asset has been treated differently in rates. MGE's prepaid pension asset is in effect the opposite of the accumulated deferred income tax reserve. Deferred income taxes represent income tax paid through rates that exceed the Company's current income tax liability. The deferred taxes represent a cash flow benefit to the utility and are returned to customers over the life of the assets generating the accelerated tax deductions used in calculating current income tax. The prepaid pension asset represents the accumulated reduction in rates that has occurred as a result of reflecting negative pension cost in rates under FAS 87 for MGE from the mid-1990s to 2004. As long as FAS 87 ratemaking for pensions was maintained for MGE, the prepaid pension asset was considered to be a temporary timing difference that would reverse over time. With a change in pension cost determination to the minimum ERISA funding requirement in MGE's 2004 rate proceeding, the only mechanism to reverse the prepaid pension asset was to amortize the balance over a reasonable period of time. The Staff believes the appropriate time frame for amortizing MGE's prepaid pension asset is the number of years that FAS 87 was in effect for ratemaking purposes, or seven years.

Also, as a result of the 2004 Stipulation and Agreement, MGE was authorized to use an accounting mechanism to "track" the difference between the minimum ERISA amounts used to set the Company's rates and the actual contributions MGE made to its pension trust funds as a result of subsequent minimum ERISA calculations. This difference was to be booked by MGE as a regulatory asset or regulatory liability, depending upon whether the pension expense amount set in rates was greater than or less than the Company's actual pension expense as measured under the minimum ERISA calculation. After the 2004 rate case, MGE booked a regulatory asset for the excess of its actual pension expenses over its 2004 pension rate allowance, and this asset was included in MGE's rate base and amortized to expense over five years in the Company's next rate case, No. GR-2006-0422. Since its 2006 rate case, MGE has continued to track its pension expense level in rates against its incurred expense. Along with the previous 2004 rate case tracker regulatory asset, the new regulatory asset/liability is being included in rate base and amortized to expense over five years. The Staff has combined the prepaid pension and the tracker amounts in rate base into one line item, entitled "Prepaid Pension Asset".

Staff Expert: Keith D. Foster

F. Net Cost of Removal Regulatory Asset

As part of the Stipulation that was approved by the Commission in Case No. GR-2004-0209, the Staff and MGE agreed to the future accounting for net cost of removal by MGE. The Staff and MGE agreed that the net cost of removal for ratemaking purposes be treated as a current expense and set at a level of $771,039. The 2004 Stipulation also required MGE to record any difference between the rate case provision ($771,039) and the actual levels of annual net cost of removal in a regulatory asset/regulatory liability account. The 2004 Stipulation provided that any such net regulatory asset/regulatory liability would be included in rate base of MGE in its next rate case and amortized over a five-year period. The final amount for the regulatory asset was determined in the last case to be $850,256 which is being amortized over five years. The remaining balance as of April 30, 2009 is $495,981 and is included as an addition to rate base.

Staff Expert: Amanda C. McMellen

G. Customer Deposits

The amount of customer deposits on Accounting Schedule 2, Rate Base represents a 13-month average (April 2008 – April 2009) of MGE's customer deposits. Customer deposits represent funds received from utility companies' customers as security against potential loss arising from failure to pay for utility service. These deposits are available to the utility for general use. Since the deposits are essentially interest-free loans to the company, a representative level is included as an offset to the rate base investment in order to ensure that the Company does not earn a return on the value of the level of deposits. In addition, since these funds were provided by the ratepayers and not the shareholders,.the ratepayers should be allowed to earn the same rate of return on these funds as the one used to compensate the shareholders for their capital invested in the utility.

Interest is also accrued on these customer deposits based upon a rate specified in the Company's tariffs in Sheet No. R-14. When a customer becomes eligible for a return of his or her deposit, the amount refunded includes the accumulated interest. The annual accrual of interest on customer deposits is included in the cost of service as an expense. The amount of interest calculated on customer deposits is reflected on Staff Accounting Schedule 10 as Adjustment E-117.1.

Staff Expert: Amanda C. McMellen

H. Customer Advances

Customer advances are funds provided by individual customers of the Company to assist in the costs of the provision of electric service to those customers. Customer advances essentially represent interest-free funding available to the Company. Therefore, it is appropriate to include these funds as an offset to rate base because (use the language like whatever you decide to use in customer deposits above). Because customers will not receive a refund of any portion of the customer advance, no interest is paid to those customers for the use of their money, unlike the situation with customer deposits. The amount of customer advances reflected on Accounting Schedule 2, Rate Base represents the balance as of April 30, 2009, the end of the Staff's update period.

Staff Expert: Amanda C. McMellen

I. Deferred Income Taxes

1. Deferred Income Taxes – SLRP

The Service Line Replacement Program (SLRP) deferred tax line relates to the fact that, for income tax purposes, the Company was previously allowed to currently deduct SLRP expenses that were being deferred for financial reporting purposes through Commission authorization of accounting authority orders. This situation gives rise to a tax timing difference. Normalization of tax-timing differences meant that MGE customers are required to pay to the Company in rates amounts associated with income taxes on the tax-timing difference items prior to when the Company will pay the associated income taxes to taxing authorities. Recognizing a rate base deduction for past SLRP deferred taxes gives customers appropriate credit for providing funds to the utility to use for general corporate purposes for a period of time before payment to the taxing authority.

Staff Expert: Amanda C. McMellen

2. Deferred Income Taxes – Allocated Plant

The Staff adjusted MGE's allocated accumulated deferred income taxes to reflect the change in the corporate allocation factor to include Citrus Corp (Citrus). This is discussed in Corporate Allocations in Section VII (C).

Staff Expert: Amanda C. McMellen

3. Accumulated Deferred Income Taxes/AMT Credit

MGE's deferred tax reserve represents, in effect, a prepayment of income taxes by MGE's customers before payment by MGE. As an example, because MGE is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes paid by MGE is considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to MGE. Therefore, MGE's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences that are created through the ratemaking process should be reflected in rate base. The Staff has taken this approach in calculating the deferred income tax rate base offset amount in this case. The deferred tax impact of past tax timing differences for the balance of SLRP deferrals is also included in the Staff's rate base offset.

For MGE, the rate base component Alternative Minimum Tax (AMT) Credit is directly related to, and in fact, is an offset to deferred income taxes. As a result of certain IRS regulations, over the past several years Southern Union has been what is referred to as an "AMT taxpayer." IRS regulations reduce or eliminate certain corporate tax benefits used to reduce taxable income if a company's regular income tax falls below a certain threshold. One of the major tax benefits reduced is accelerated tax depreciation. While the deferred tax reserve is set up to reflect the full income tax effect of book-tax depreciation timing differences, the tax effect of the amount of accelerated tax depreciation which is not allowed to be deducted on the current year's tax return is recorded as an AMT tax credit. The AMT credit is a reduction in accumulated deferred income taxes and has the effect of increasing MGE's rate base. MGE does not file a separate tax return from that of its parent, Southern Union. Instead, Southern Union calculates its tax liability, including the AMT credit amount, on a consolidated basis, which includes MGE's financial results.

Staff Expert: Keith D. Foster

VII. Corporate Allocations

A. Background

MGE is a division of Southern Union Company (SU) and therefore affiliated with Panhandle Energy (PE), Southern Union Gas Services (SUGS), and New England Gas Company (NEG). All of these entities are major divisions or subsidiaries of SU.

B. Joint and Common Costs Allocations Model

The corporate division of Southern Union provides MGE with services from its financing, financial reporting, corporate governance, risk management, human resources, legal and environmental departments. Southern Union is composed of 14 corporate departments consisting of 99 employees.

In previous cases, the only corporate allocated expense that MGE recorded on its income statement was its share of Southern Union's insurance costs. While MGE did capitalize corporate overhead costs to its plant records as a component of the original cost of utility plant throughout the year, it did not record corporate allocated operations and maintenance (O&M) expenses on its income statement, although MGE did seek recovery of these costs in Missouri rate cases through proposed adjustments to expense. At the end of calendar year 2008, MGE adjusted its books to include an amount in expenses for certain corporate allocations for the first time. Beginning in 2009, allocations of corporate expenses are being accrued monthly on MGE's books as an "outside service" to account 923, Outside Services Employed.

The joint and common costs associated with the aforementioned corporate services are allocated to Southern Union's divisions and affiliates, including MGE. Southern Union assigns and allocates costs through the Joint and Common Cost Model (JCC Model). The primary allocation methodology used within the JCC Model is the "Massachusetts Formula" which is a method that is generally accepted by the Federal Energy Regulatory Commission (FERC). As used by Southern Union, the Massachusetts Formula approach uses the relative amount of each affiliates' (1) investment; (2) revenue; and cash operating expenses (operations and maintenance expense plus taxes other than income and depreciation). This three-part formula is the same methodology recommended by the Staff in Case No. GR-2004-0209 and also used in Case No. GR-2006-0422. The Staff continues to believe that the allocation results of the JCC Model are a reasonable approach to distributing joint and common corporate costs to MGE in this case, with the exceptions discussed within.

The Staff's revenue requirement calculation in this case reflects use of the JCC Model based on actual Southern Union costs based upon the test year ended December 31, 2008. It should be noted that Southern Union does retain some costs that it determines that should not be allocated to its division or affiliates.

C. Non-Employee Related Costs

Non-employee costs include such expenses as Southern Union professional fees, outside services, directors' fees, financial reporting, and printing and reproduction fees. Southern Union's non-employee-related allocation process assigned $2,928,649 of its cost to MGE. The Staff recommends that $989,793 be included in MGE's revenue requirement for non-employee related costs.

The Staff made a number of adjustments concerning Southern Union's non-employee related expenses. First, the Staff excluded 2008 costs associated with its old Scranton, PA office. The Scranton office was previously the headquarters for the Pennsylvania properties, with which the Company is no longer affiliated.

The second adjustment relates to the process by which costs are allocated to the different affiliates of Southern Union. The JCC Model (discussed above) would utilize two different factors in order to allocate certain costs to MGE. The first factor of 10.5435% allocates costs between all affiliates of Southern Union. The second factor of 14.786% allocates costs between all the affiliates except Citrus. Citrus is owned 50% by Southern Union and 50% by El Paso Corporation (El Paso). Citrus Corp owns 100% of Florida Gas Transmission Company, which is an open-access interstate pipeline extending from South Texas through the Gulf Coast region of the United States to South Florida. The Staff believes that Southern Union's management, along with El Paso, has ultimate responsibility for the operations and activities of Citrus, and accordingly should include Citrus in all allocation calculations. The Staff has made an adjustment to reallocate these costs based on the 10.5435% factor, to ensure that MGE is not assigned costs properly attributable to Citrus' operations.

During the review of the JCC Model results, there were a small number of accounts that the Staff could not reconcile to the Company's numbers. The Staff has asked for additional documentation to explain and justify these costs but has not received any information to date. An adjustment was made to eliminate these costs until further information is provided to the Staff. Also, the Staff attempted to review all legal expenses that were allocated to all Southern Union divisions and not directly assigned to one of them. Additional documentation is needed to complete this review, and has been requested but not yet provided. Costs associated with items that could not be verified have been eliminated until the Company can provide the proper documentation for the Staff to review.

The Staff made no adjustments to MGE's proposed allocated level of insurance premiums. The Staff includes MGE's proposed level of corporate allocated insurance expense as part of its insurance expense adjustment. Also, the Staff made adjustments to MGE's proposed level of corporate allocated plant, reserve and deferred taxes associated with the Company's headquarters in Texas. The Staff made these adjustments to reallocate these amounts based on the allocation percentage including Citrus (which is discussed above). The proper amounts are reflected in Staff Accounting Schedule 2, Rate Base, Accounting Schedule 3, Plant in Service and Accounting Schedule 6, Depreciation Reserve. Consistent with past Commission precedent, both the Company and the Staff have excluded Southern Union's New York City Office from MGE's cost of service in this case.

D. Employee Related Costs

South Union's employee-related costs are organized by corporate department and are composed of the following costs: (1) Payroll, including base wages, incentive compensation and overtime and payroll related taxes; (2) Employee benefits, including vacation pay, sick pay, 401(K) matching and insurance costs, etc; and (3) Other employee related costs. Southern Union's employee-related allocation process assigned $2,325,312 of costs to MGE. The Staff recommends that $1,052,151 of this allocated cost category be included in MGE's revenue requirement. The Staff made a number of adjustments concerning Southern Union's allocated employee-related expenses. First, the Staff adjusted the salary of Southern Union's Board of Directors Chairman, Mr. George Lindemann. Second, the Staff did not include any corporate incentive compensation costs (short or long term). Also, the Staff eliminated several salaries related to certain Information Technology (IT) Department positions.

The Staff included total compensation of $325,000 for Mr. Lindemann to recognize that Mr. Lindemann's relationship to Southern Union is more as a member of the Board of Directors than that of an active full-time executive officer. Southern Union's highest compensation for a member of the Board of Directors was approximately $106,000 in 2008. Recognizing that Mr. Lindemann plays a more significant role in Southern Union's operations than the average Board member, the Staff believes that annual compensation of $325,000 (over three times the salary of the highest paid Board member) was reasonable. The Staff has proposed adjustments to Mr. Lindemann's allocated salary expense in prior MGE rate cases. The Commission has ruled on the issue of an appropriate level of compensation for Mr. Lindemann in MGE's previous rate cases, Case Nos. GR-96-285 and GR-2004-0292. In both of these cases, the Commission found that Mr. Lindemann's total salary compensation was excessive and that MGE's allocated portion of his salary should not be included in rates in entirety. In this case, the Staff has not seen any evidence that Mr. Lindemann functions in any different capacity as Southern Union's Chief Executive Officer as in its previous audits.

The Staff reviewed the allocated corporate costs associated with Mr. Eric D. Herschmann, Southern Union's President and Chief Operating Officer. Southern Union's April 16, 2009 Proxy Statement (Proxy) noted, in regard to Mr. Herschmann's annual salary, that Southern Union's Board of Directors' Compensation Committee "approved a total compensation package for Mr. Herschmann that was more similar to that of a chief executive officer rather than the chief operating officer benchmarked positions evaluated by the external compensation advisor. In making a determination with respect to Mr. Herschmann's total compensation, the Committee was aware of Mr. Herschmann's continued employment with the Kasowitz firm."

The above excerpt from Southern Union's Proxy indicates that Southern Union has decided to compensate both of its two top officers at levels typical of CEO positions. Notwithstanding this practice, in light of the Staff's proposed disallowance of a portion of Mr. Lindemann's allocated salary, the Staff chose not to adjust Mr. Herschmann's allocated salary in this proceeding

Southern Unions Proxy lists one of the goals of its short-term incentive plan to "motivate near-term drivers of stockholder value." (page 21). That document also lists as a goal of Southern Union's long-term incentive plan to "directly align rewards with stockholder returns and share performance" (page 22). The Staff did not receive any evidence that demonstrates that these incentive plans benefit ratepayers as opposed to primarily benefiting shareholders. The Commission consistently excludes incentive compensation costs that are based primarily on criteria that benefit utility shareholders or that are not directly related to the provision of safe and adequate utility service in Missouri.

Finally, since the last rate case, Southern Union has substantially increased the number of positions in the IT department. Prior to December 2002, substantially all of Southern Union's IT functions were consolidated and coordinated through Southern Union's corporate headquarters in Austin, Texas (Southern Union's corporate headquarters subsequently moved to Wilkes-Barre, Pennsylvania, and then to Houston, TX). The IT department costs were charged to the corporate books and allocated to MGE and the Southern Union Gas (SUG) division when these operating divisions filed rate cases in their respective jurisdictions. SUG was Southern Union's local gas distribution company (LDC) located in Austin, Texas. Like MGE, it operated as a division of Southern Union Company. On October 16, 2002, Southern Union Company announced the agreement to sell its SUG division to ONEOK, Inc. (ONEOK) headquartered in Tulsa, Oklahoma. The sale was completed in January 2003. As a result of this sale, MGE created its own internal IT department to operate more as a stand-alone operation for this function. MGE's new IT department initially consisted of many of the IT employees that were on the corporate books before the sale of Southern Union Gas. In Case No. GR-2004-0209, adjustments were made by Staff to incorporate an annualized level of payroll expense for its new IT employees in the Company's cost of service. At the time of the 2004 rate case, the Staff justified the inclusion of the new IT positions in its cost of service by stating that these costs would be offset in part by a reduction in allocated corporate costs for IT services.

In this case, the Staff has noted no decrease in the number of internal MGE positions in the IT function. Given this history, the Staff questions why the benefits of the IT decentralization actions taken earlier in this decade should now be countermanded by Southern Union's increase in IT personnel without clear justification of the need for these positions and demonstration of benefit to MGE. For this reason, the allocated costs associated with all positions added to Southern Union's IT Department since the Staff's review of corporate allocations in the last MGE rate case have been eliminated by the Staff's adjustment.

Staff Expert: Amanda C. McMellen

VIII. Income Statement

A. Revenues

1. Introduction

The following section describes how the Staff determined the amount of MGE's adjusted operating revenues. Since the largest component of operating revenues is a result of rates charged to MGE retail customers, a comparison of operating revenues with the cost of service is fundamentally a test of the adequacy of the currently effective retail natural gas rates to meet the Company's current costs of providing utility service. If the overall cost of providing service to the retail customers exceeds operating revenues, an increase is required in the rates currently charged by MGE to its retail customers.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between a company's cost of service and its operating revenues. Test year revenues need to appropriately normalized and annualized in order to accurately measure the amount of any deficiency (or excess) in the current level of operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting retail rates (i.e., rate revenue) prospectively.

2. Definitions

Operating Revenues are composed of two components: (1) Rate Revenue; and (2) Other Operating Revenue. The definitions of these components are as follows:

Rate Revenue: Test year rate revenues consist solely of the revenues derived from MGE's authorized Commission charges for providing natural gas service to its retail customers. MGE's variable charges are determined by the amount of each customer's usage and the (per unit) rates that are applied to that usage. Each customer also pays a flat monthly customer charge dependent upon each customer's rate class. These rate classes include residential, commercial, industrial, and transportation customer classifications.

Other Operating Revenue: Other operating revenue includes late payment charges, collection trip charges, special meter reading charges and disconnect/reconnection of service charges. Each of these charges are also established by the Commission, and all of these revenue items are taken into account in setting retail rates for MGE's gas service to customers.

3. The Development of Revenue in this Case

To determine the level of MGE's revenue, the Staff has applied standard ratemaking adjustments to test year (historical) sales (Ccf) and revenue data. The Staff makes these adjustments to test year rate revenues in order to determine the level of revenue that the

Company would collect on an annual basis, under normal weather or climatic conditions, based on information that is "known and measurable" as of the end of the update period. In this particular case, the test year is the 12 months ending December 31, 2008, and the update period ends April 30, 2009.

Revenue has been developed and summarized by the Staff in two different ways: (1) by type of regulatory adjustment; and (2) by total revenue by rate class. The attached Table (Appendix 3) to this Report summarizes in both manners, the Staff's position as to rate. The rate classes shown on this Table are Residential, Small General Service (SGS), Large General Service (LGS) and Large Volume Service and Transportation Service. The Staff workpapers provide the source numbers and analysis, as well as a more detailed version of the attached summary table.

This Report describes the five major regulatory adjustments the Staff made to test year billed rate revenues:

a. weather normalization

b. 365-day adjustment

c. customer growth

d. large customer annualization

e. removal of gas costs

Not all of these adjustments affect both sales and rate revenue, and not all rate classes are subject to all five adjustments.

Other revenue adjustments proposed by the Staff in this proceeding are also briefly described in the following COS Report sections.

Staff Expert: Amanda C. McMellen

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normal Variables Used for Weather Normalization

This Commission uses a "test year" to determine revenues and set appropriate rates. Natural gas sales vary from year to year based on weather conditions. Since each year's weather is unique, test-year sales need to be adjusted to "normal" weather. Normal weather is characterized as an average daily temperature for each day calculated over a 30-year period. Currently, the time period used by the Staff in determining the normal values of weather variables is the 30-year period (January 1, 1971 - December 30, 2000), which is used by the NOAA[8] and the World Meteorological Organization (WMO) to calculate normal weather variables. Natural gas sales are predominantly influenced by ambient air temperature, so daily average temperature and the derivative measure, heating degree days (HDD)[9], are the measures of weather used in adjusting natural gas revenues.

To develop "normal" average temperatures to compare with the test year temperatures the Staff used weather records from the weather station at Kansas City International Airport (MCI) for MGE's Kansas City and St. Joseph service areas. For MGE's southern service area, Staff used records from the Springfield, Missouri (SGF), weather station to calculate normal weather. Both these stations are designated by NOAA as First Order Weather Stations. First-order weather stations are usually located at regional or municipal airports, where professional observers continuously monitor the weather instruments. The NOAA certified instruments at MCI and SGF record daily maximum and minimum temperatures, with hourly observations of precipitation, temperature, dew point, wind and other weather elements.

---

[8] U. S. National Oceanic and Atmospheric Administration

[9] Heating Degree Days (HDD) are used as an index to estimate the amount of energy required for heating during the winter season. (HDD=65oF – Daily Average Temp, however, if Daily Average Temp > 65oF, then HDD=0); (Daily Average Temp = (Daily Maximum Temp + Daily Minimum Temp)/ 2).

NOAA initially calculates monthly normal temperatures over the 30-year normals period, these monthly normals are not directly usable for Staff's purposes. The Staff's weather normalization methodology relies on daily temperature data. Consequently, daily normal temperatures are developed to adjust natural gas usage (sales) to normal levels. The Staff's daily data is adjusted such that the average of the adjusted daily temperature corresponds with NOAA's monthly average.

Staff uses Normal and Actual heating degree days (HDDs) to weather normalize gas sales. To determine daily normal HDDs Staff averages the adjusted daily actual HDDs for each calendar date. For example, the 30 observations of actual HDDs for January 1, of each year for the years 1971 through 2000, were averaged to determine the normal HDDs for January 1. The normal peak-day HDDs for each of the 12 months were calculated as the average of the HDDs of the coldest day in each of the 12 months. This information was made available to Staff witnesses Henry Warren, Tom Imhoff, and Dan Beck to use in calculating weather normalization adjustment factor and class cost of service allocation factor.

Appendix 4 to this Cost of Service Report, Summary of Heating Degree Days, presents calendar month summaries of the adjusted daily actual and normal HDDs during the test year for MGE. The weather data shows that the test year (January 1 – December 31, 2008) was approximately 7% cooler than normal for MGE's Kansas City and St Joseph service area and approximately 5% cooler than normal for their southern service area.

Staff Expert: Manisha Lakhanpal

i. Weather Normalization of Sales

This analysis addresses the Commission Staff's (Staff) weather-normalization of natural gas sales for the firm general service customers of Missouri Gas Energy, (MGE or Company) for the test year ending December 31, 2008. Residential rates are not based on usage, so this rate class is not adjusted for weather. MGE's General Service rates are based on natural gas usage so it is important to remove the influence of abnormal weather from the test-year. Natural gas is predominately used for space heating in Missouri. MGE's level of natural gas sales varies depending on weather conditions, so MGE's sales may increase or decrease depending on the duration and intensity of colder weather. Staff makes weather-normalized adjustments to the amount of natural gas sales to adjust sales for deviations from normal weather conditions during the test year.

MGE's billing records were subdivided into three geographic regions: Joplin, Kansas City, and St. Joseph. Staff witness Manisha Lakhanpal calculated and provided to me both the daily actual and daily normal heating degree days (HDD) for each of the three geographic regions. In her section of the report, Ms. Lakhanpal discusses how she calculated HDD.

For each billing cycle, MGE provided Staff monthly natural gas sales in hundreds of cubic feet (Ccf) and monthly numbers of customers by firm customer class and geographic region. The Company divides its natural gas accounts into billing cycles, whose meters are read throughout a month. Next, the Company bills the accounts based on the meter reading. Since there are approximately twenty-one working days in a month, customers' accounts are usually grouped into one of the approximately twenty-one billing cycles. Staff calculated two sets of twelve billing month averages, by customer class, for the small general service and large general service classes in each of the three geographic regions. One set of these averages was the daily average natural gas usage in Ccf and another set was the daily average HDD.

Staff calculated billing month averages from the data on numbers of customers, natural gas usage in Ccf, and summed HDD from approximately twenty billing cycles for each billing month, by customer class. These two sets of billing month averages (usage and weather) were used to study the relationship between space-heating natural gas usage in Ccf and in colder weather.

Staff used regression analysis to measure the relationship between daily space-heating sales per customer, in Ccf, to the daily HDD. Staff's analyses resulted in decreases to natural gas sales because the weather during the test year was warmer than normal. Staff's analyses resulted in an approximate decrease of 0.1 percent for the residential class due to an adjustment for days in the billing cycles, an approximate 4.9 percent decrease for the small general service class for weather and cycle days, and an approximate 5.0 percent decrease for the large general service class for weather and cycle days (Schedules 1.1 - 1.9). These decreases do not include the Staff's customer growth annualization.

MGE's current SGS rates are divided into two blocks. For SGS customers, the *first block, or initial block,* contains the first 600 Ccf (hundred cubic feet) of natural gas used in the month and the *second block, or tail block,* contains all volumes over 600 Ccf per month. In order for Staff witness, Ms. Amanda McMellen, to compute the revenues associated with the normal volumes, the normal volumes must be properly allocated monthly to each block to determine the rate at which the volumes are to be computed. The Company provided Staff with test year monthly active meters and volumes by block for the SGS rate code and customer classes served on the SGS tariff. I used the Company's test year blocked volumes to determine the percentage of usage falling into each rate block for each month in the Kansas City District, St. Joseph District, and Joplin District.

For the SGS class, using the monthly blocked data for January – December 2008, the monthly percent of use in the initial block has a high correlation with the monthly average use per customer per day. I observed that in the lower heating months of May through October the percent in the first block is nearly constant. In these months the use per customer is less than 125 Ccf. I used a simple average of the percent in the first block in the test year months May-October to estimate the normal percent in the first block for the months of May-October. For the remaining months, November-April, which have more heating use, I used regression analysis to estimate normal billing units in each month. Using the Company's test year monthly customer counts and bill frequencies for the SGS class, I used the monthly Ccf per customer per day in the test year months of January – December 2008 to estimate an equation that related it to the monthly percent use in the first block. Next, I used normal monthly usage per customer in the regression equation to estimate the normal monthly percent in the first block (Schedules 2.1 - 2.3).

To compute the adjustment to test year volumes to yield the estimated normal volumes, I set the adjustment in the second block equal to the total minus initial block adjustment (Schedules 3.1 - 3.3). The difference between the predicted normal usage volumes and test year volumes gives an estimated monthly adjustment for the first block (Schedules 3.1 - 3.3). The monthly adjustments to Test Year volumes in the blocks are in the last column of the Tables in Schedules 3.1 - 3.3. The monthly adjustments are summed into seasonal and annual totals.

Schedules 3.1 - 3.3 contain the adjustment volumes for each billing month during the test year. The total adjustment for the SGS customer classes is a negative 7,977,825 Ccf. The total of these adjustments accounts for 100% of the adjustments made to both the first and second blocks. The volumes were allocated to the blocks for the SGS class as shown in Schedules 3.1 - 3.3. These adjustments were supplied to Staff witness Ms. Amanda McMellen for use in the customer growth revenue adjustment.

Staff Expert: Henry Warren

b. Customer Growth

MGE's service territory covers much of the western portion of Missouri. The Company's customers are segregated into three different regions within the Company's service territory. These regions include Joplin (including Monett), St. Joseph and Kansas City (including the Kansas City North, Independence, Lee's Summit, and Warrensburg territories). Each region serves four classes of customers: residential, general service (small and large), large volume and transportation customers. All revenue adjustments made by the Staff in determining the Company's cost of service were priced on the margin (the total rate excluding Purchased Gas Adjustment (PGA) gas cost rate) included in the Company's tariffs. The Staff analyzed customer growth for the Residential, SGS and LGS classes. Adjustments for the Transportation (large volume) customers are discussed in Section VIII (A4 c) of this report.

The annualization of customer revenues contains two components, the base charge and the commodity charge. The base charge is the minimum monthly charge that MGE assesses to a customer for supplying the gas service. The monthly base charge revenue is calculated by multiplying the base charge by the Staff's annualized level of customers on a monthly basis.

Unlike the situation with electric utilities, gas customers tend to fluctuate seasonally over a 12-month period, with some customers leaving the system during the spring and summer months and then rejoining the system during the fall and winter months.

This seasonality in customer numbers makes it impractical to base a customer growth adjustment on one period-ending customer number value. To appropriately take into account seasonal customer number fluctuations, the Staff used a three-step process to calculate customer growth for three of MGE's different classes of customers (residential, SGS and LGS).

During the first step, the Staff divided each month of the year by the twelve-month total of customers for that same year to determine the percentage of customers within each month to the period-ending total. Then, the Staff added the percentage of each month of the past five years (January 2007 thru January 2008, February 2004 thru February 2008, etc.) and divided that number by five to derive the monthly average of each month to the period-ending customer total for the five-year period.

The second step of the process involved dividing the December level of customers for each year by the twelve-month average of the following year. This process created a percentage that was summed for the most current five years, and then divided by five to determine a five-year average.

The third step of this process was to take this number and divide the December 31, 2008 customer count by the five-year average that was determined in the second step above. By multiplying this five-year average by twelve the annualized number of customers is derived. The annualized number of customers was then multiplied by the monthly percentage that was created in the first step to create average monthly customers for each month of the test year. These average monthly customer numbers provided the basis for the Staff's customer growth revenue adjustment.

The Residential class currently pays only a base charge, and not a variable charge, due to the "straight fixed/variable" rate design approved by the Commission for this class in

MGE's last general rate proceeding. The Staff's annualized base charge revenue for residential customers is the sum of the twelve individual monthly base charge revenues. The commodity charge is the rate MGE charges general service and large volume customers for each Ccf of gas usage. LGS customers have only one commodity charge rate block, while SGS customers has two commodity charge rate blocks. For SGS customers, block one represents a monthly usage of 0 through 600 Ccf and block two represents usage over 600 Ccf. Please refer to Section VIII.(A.4.a.i) of the Report for an additional discussion of this topic and for the assignment of Ccf usage between blocks. The Staff used this same methodology for customer growth for all classes.

For SGS customers, the Staff allocated the normal monthly usage to each of the Company's rate blocks and then multiplied the blocked usage by the appropriate block commodity charge. The sum of that calculation for each rate block for each of the twelve months was the Staff's annualized commodity revenue. The total annualized revenue for the SGS and LGS rate classes was calculated by adding the annualized base charge revenues to the annualized commodity charge revenue. Generally, customer levels are higher in the winter months and decrease during the summer months. Likewise, normal usage per customer is greater in the winter months than in the summer months. Distributing customers through the 12-month period enables the Staff to more accurately annualize revenues to reflect seasonal impact on usage.

SGS and LGS customers have two commodity charges covering different periods (November through March and April through October) of the year. In addition, SGS customers have two usage rate blocks as discussed earlier in the Report. To annualize the commodity charge revenues, the monthly level of customers by customer class was multiplied by the Staff's weather normalized usage per customer. The LGS normal monthly usages were then multiplied by the seasonal commodity charge to determine the monthly commodity charge revenues. For SGS customers, the Staff allocated normal monthly usages to the Company's rate blocks.

An additional adjustment to revenues made by the Staff is an adjustment which can be attributed to "rate switching." Rate switching is the term given to a situation in which a customer changes their rate classification, and can occur for a number of reasons. For example, the nature of a customer's operations may have changed and another customer class may become more appropriate. Or the customer may find it to be more economical to switch to another customer class, or a customer may decide to procure its own gas, which would also make a rate switch necessary. Please refer to the next section of this report for further discussion of this topic.

Staff Expert: Amanda C. McMellen

c. Large Volume Service Customer Adjustments

MGE has approximately 400 customers in its Large Volume Service (LV) rate class. The customers in this class are commercial and industrial customers that are expected to use more than 15,000 Ccf of gas during any month of a 12 month period. LV customers can either contract with MGE for sales gas, or can purchase their own gas and have it delivered by MGE. The margin rates paid by both types of LV customers are the same.

All LV customers' rate components consist of a monthly customer charge, a two-block, seasonal usage charge, and a monthly charge for each electronic gas meter. There were three types of adjustments made to the revenues of this customer class.

1. Rate-Switching Adjustment

This type of adjustment is made when a customer takes service in two or more of the company's rate classes during the test year. In this case, the customer's usage is adjusted so that all usage is counted in the customer class in which the customer was taking service at the end of the test year. These customers' usage, and the associated revenue, is removed from the class(es) in which it took service during any other months; this usage is then priced out at the year-end customer class rates, and those revenues are added to that class' test year revenue.

During the test year, two customers transferred from MGE's Small General Service (SGS) class to the LV class. This resulted in a negative dollar adjustment to the SGS rate revenues to reflect the customer charges and usage charges that were billed under that rate.

These customers' billing determinants were then priced out using the LV tariffed rates, and these revenues were added to the LV rate revenues for the calculation of current revenues.

2. Customer Gains/Losses Adjustment

Another type of adjustment made to the LV customers' rate revenues reflects LV customers that either began taking service on the MGE system during the test year, or that quit taking service on the MGE system during the test year.

There was one LV customer that began taking service during the test year. In this case, the customer came on the system in April 2008; thus, there was no usage for January-March 2008 reflected in the company's test year revenues. Using the customers' usage from January-March 2009, Staff imputed, or 'filled in', the usage for those 3 months.

Four LV customers went completely off the MGE system during the test year. These customers' usage and volumes, and the associated revenues, were removed from the LV class rate revenues.

3. Weather Normalization Adjustment

The final adjustment made to LV customer usage and rate revenues reflects the weather sensitivity of some of the LV customers; for example, schools. This adjustment was made using the Staff's weather and normalization method as described in the weather normalization section of this report.

Staff Expert: Anne Ross

d. Other Revenue Adjustments

The Staff made several additional adjustments to the Company's per book revenues. Adjustments were made to each revenue category to remove the test year gross receipt taxes from the operating revenues. Gross receipt taxes are not operating revenues. In respect to gross receipts taxes, the Company acts merely as a collecting agent and remits the taxes to the appropriate taxing entities. The Staff also made adjustment E-117.1 to remove gross receipt taxes from the Taxes Other Than Income Taxes line item within the expense portion of the income statement. Gross receipt taxes are reported as both a revenue and expense item on the Company's books. Therefore, both revenue and expense adjustments are necessary to eliminate this item.

The Staff made adjustments to eliminate unbilled revenues from the test year. The unbilled revenue adjustment is made to reflect the Company's test year revenues on a billed basis. In the test year, there are gas sales to customers relating to either usage periods outside the test year, as well as gas usage that has not yet been recognized on issued bills. To recognize this usage for financial reporting purposes, utilities generally book an estimate of unbilled revenue on its books. The purpose of the Staff's unbilled adjustment is to remove any estimated revenues from the test year of the company's actual monthly revenues. For purposes of a rate case, the Staff's adjusted level of revenues should be based upon actual billed revenues only.

Adjustment E-9.1 is line item adjustment to reflect MGE's test year per book expense for gas purchases. Gas purchase expenses are estimated and assessed to ratepayers outside of general rate proceedings through MGE's Purchased Gas Adjustment (PGA) Clause. The PGA Clause provides MGE an estimating methodology for recovering purchased gas expense, which is subsequently trued-up through the Actual Cost Adjustment (ACA) mechanism. Therefore, purchased gas expenses and revenues generally are netted to equal zero for purposes of general rate cases. Adjustments were made to eliminate PGA revenues for the test year from the appropriate revenue accounts. Adjustments were made to remove the take-or-pay portion of the PGA revenues and to adjust the PGA revenue for the ACA true-up mechanism.

The Staff made adjustments to remove the Panhandle Eastern Pipeline Company refund/deferral from the cost of service to derive the appropriate actual test year margin results. Adjustments were made to remove contract demand credits from commercial and industrial revenues to derive the appropriate test year margin results. The Staff made an adjustment to add the Succession Rate Code 48 costs (the "Company use" gas costs) to commercial SGS gas sales. An adjustment was made to remove the gas used by the Company from the cost of service to derive the appropriate actual test year margin results. The Staff made an adjustment to remove the Infrastructure System Replacement Surcharge (ISRS) revenue not in included in base rates from the cost of service to derive the appropriate actual test year margin results. An adjustment was made to remove the daily balancing not in MGE's Customer Service Software (CSS) from the cost of service to derive the appropriate actual test year margin. The Staff made an adjustment to remove the credit adjustment not in CSS from the cost of service to derive the appropriate actual test year margin results.

Staff Expert: Amanda C. McMellen

B. Depreciation

In the present case the Company's depreciation consultant, Thomas J. Sullivan, recommended the following changes to MGE's current depreciation rates in his direct testimony:

1. A 32-year average service life ("ASL") and a net salvage percentage of negative 8%, resulting in a 3.38% depreciation rate for Account 380, Services;

2. A net salvage percentage of negative 5.28% (and retaining the currently ordered 44-year ASL), resulting in a 2.39% depreciation rate for Account 376, Mains;

3. Establishment of a separate sub-account, 392.1, for Transportation Equipment [Cars and Small Trucks], with a 6-year average ASL and a net salvage percentage of positive 20%, resulting in a 13.33% depreciation rate for this account; and

4. A 10.5-year ASL and net salvage percentage of positive 20% for subaccount 392.2, Transportation Equipment [Large Trucks], resulting in a 7.62% depreciation rate for this account.

In addition, Company witness Michael R. Noack recommended the following changes to the current depreciation rates for MGE's Corporate Plant accounts, in Schedule H-12 attached to his direct testimony:

1. A 2.5% depreciation rate for Account 390, Leasehold Improvements; and

2. A 11.69% depreciation rate for Account 391, Office Furniture & Equipment

The changes to MGE's depreciation rates recommended by both Mr. Sullivan and Mr. Noack were made without the benefit of a updated comprehensive depreciation study. MGE's last depreciation study was submitted to the Staff in June 2005.

In its audit, the Staff began a review of the capital assets of the gas operations of MGE. Early in its review, Staff notified the Company that the requirements of 4 CSR 240-3.235(1)(A) required the Company submit a new depreciation study, mortality database, and property unit catalog with its rate case filing or, as a minimum, request a waiver from such requirements. The Company subsequently applied, in Case No. GE-2010-0030, to the Commission for a waiver from the Commission's rule. As part of Staff's recommendation for the waiver to be granted, Staff recommended that several conditions be imposed on or agreed to by the Company regarding changes to its depreciation rates, and appropriate recordkeeping of its historical mortality data and cost of removal/salvage data. Both MGE and The Office of Public Counsel (OPC) subsequently made filings agreeing with the Staff's conditions for acceptance of the waiver request.

The Company's limited historical mortality data, available since only 1994, has been an issue in this case and the Company's most recent rate cases, Case Nos. GR-2006-0422, GR-2004-0209, GR-2001-292, and GR-98-140. Staff also had recordkeeping concerns as a result of its review of the Company's historical cost of removal and salvage data in this case.

To address these recordkeeping concerns and as part of Staff's support to the Commission that the Company be granted a waiver to the requirements of 4 CSR 240-3.235(1)(A), the Staff outlined specific conditions on data recordkeeping for the Company to follow.

The Commission's Order regarding the agreed-upon conditions states:

> 2. Missouri Gas Energy, a division of Southern Union Company, shall retain the current depreciation rates, as listed in Schedule A to Staff's Recommendation, and as agreed upon in the Partial Nonunanimous Stipulation and Agreement in Commission Case No. GR-2006-0422.
>
> 3. Missouri Gas Energy, a division of Southern Union Company, shall retain the rates described in paragraph 2 except that it will add a new depreciation rate for a transportation subaccount, which was not part of the last rate case of Missouri Gas Energy, a division of Southern Union Company, as shown in Schedule A.
>
> 4. Missouri Gas Energy, a division of Southern Union Company, shall submit a depreciation study no later than June 30, 2010, which conforms to, among other things, Commission Rule 4 CSR 240-3.275 and include actuarial analysis for all accounts inclusive, identifying those specific accounts that lack sufficient data to perform an actuarial analysis.
>
> 5. Missouri Gas Energy, a division of Southern Union Company, shall use the currently authorized Missouri depreciation rates for General Plant Accounts for the respective functional accounts of its Corporate Plant accounts.
>
> 6. Missouri Gas Energy, a division of Southern Union Company, shall maintain mortality records in compliance with Commission Rule 4 CSR 240-40.040 Uniform System of Accounts – Gas Corporations and 4 CSR 240-3.275 Submission Requirements for Gas Utility Depreciation Studies.
>
> 7. Missouri Gas Energy, a division of Southern Union Company, shall account for all payments from other parties when it is required to remove, relocate, rearrange, reroute, or otherwise make changes in utility property, other than for purposes of rendering utility service, as credits to the depreciation reserve in compliance with Commission Rule 4 CSR 240-[40.]040 Uniform System of Accounts – Gas Corporations and appropriate[ly] identify amounts in their Annual Reports.
>
> 8. Missouri Gas Energy, a division of Southern Union Company, shall establish and adopt accounting policies or procedures of separation and allocation [of] removal costs of plant that is being retired from costs to install new plant.

> 9. Missouri Gas Energy, a division of Southern Union Company, shall continue to keep a separate accounting of their amounts accrued for recovery of their initial investment in plant from the amounts accrued for the cost of removal, consistent with the Commission's Third Report and Order in Laclede Case No. GR-99-315.

The Commission's Order Granting Waiver in Case No. GE-2010-0030, effective August 22, 2009, ordered the depreciation rates listed in Schedule A to Staff's Recommendation filed in that proceeding on July 31, 2009. Those depreciation rates are shown in the attached Schedule 3 to this Report. As a result of the Commission's Order, the Staff believes that all depreciation issues raised by MGE in this proceeding have been resolved.

Staff Expert: Rosella Schad

C. Payroll and Benefits

1. Payroll, Payroll Taxes, 401(k) and Other Employee Benefit Costs

The Staff has adjusted MGE's test year payroll expense to reflect an annualized level of payroll, payroll taxes, 401(k) and other employee benefit costs as of April 30, 2009, the endpoint of the test year update period ordered for this case by the Commission. The Staff is proposing an increase of $1,324,955 to the test year level of payroll costs.

Base payroll expense was calculated by multiplying employee levels at April 30, 2009, by the then-current appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll for MGE was calculated for each non-exempt employee based upon an overtime percentage computed for non-union employees and for each union. The overtime percentage for each was calculated by (1) annualizing the 40-month average of overtime hours actually incurred, (2) multiplying that by the current average April 2009 overtime rate, and (3) dividing the product by the Staff's pro forma base payroll amount.

The Staff deducted from the base payroll calculation, payroll expenses for MGE employees who spend a percentage of their time providing services to New England Gas (NEG), which is another division of Southern Union The nature of MGE's services to NEG are discussed in Appendix 5 of the Company's 2008 Cost Allocation Model.

After allocating payroll costs between construction and expense to derive an Operations and Maintenance (O&M) factor, the adjustment for payroll was distributed by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) based on the distribution calculated by the Staff updated through April 30, 2009.

The Staff calculated payroll taxes based upon April 30, 2009 wage levels and current tax rates. This included Federal Unemployment Taxes (FUTA), State Unemployment Taxes (SUTA), and Federal Insurance Contributions Act (FICA) tax. The Staff's annualized payroll and most current tax rates were used to calculate the level of payroll tax proposed in this case. In addition, payroll taxes were computed for allowable non-financial incentive payments incurred in the test year. The Company's non-financial incentive payments to its non-union employees are based on meeting target performance measures for Customer Service and for Leak Response Time as discussed in next section of this report. These incentive payments were added to each employee's base wages for 2008, to calculate the additional taxes required over the annualized salary levels.

The Company's 401(k) match costs and its costs for employee life, accidental death and dismemberment (AD&D), and Long-Term Disability insurance were also calculated based upon actual employee levels at April 30, 2009. For life and AD&D insurance, these costs were also calculated for employees on Long-Term Disability at the end of the test year, December 31, 2008. These are the only costs included in the case for these employees.

2. Incentive Compensation and Bonuses

MGE's parent company, Southern Union Company (Southern Union), has an Annual Incentive Plan (AIP) for its business units ** ______________________________ ______________________________ ** Measurement goals and a target incentive pool are established each year and communicated to all MGE non-union employees. ** ______________________________ ______________________________ __________ **

** ______________________________ ______________________________ ______________________________ ______________________________ ______________________________ ** In 2008 MGE paid out $909,140 in incentives to its employees based on the 2007's Business Unit and Corporate performance objectives. MGE has included, in its adjustments, an equal amount to eliminate these incentive payments from the test year. The Staff concurs with this adjustment as it is consistent with the Staff's position in Case Nos. GR-2006-0422 and GR-2004-0209.

** ______________________________ ______________________________ ______________________________ ______________________________ __________ ** For 2007, MGE reported the average Abandoned Call Rate achieved was 6.98% and the average Call Answer Speed was 67 seconds, both within their respective designated target range. As a result, in 2008 MGE paid out $183,030 in incentives for the

Customer Service performance component. Staff allowed these performance bonuses for achieving customer service goals.

** ** For 2007, MGE reported the average Response Time to Leak Calls was 26.87 minutes, falling within the designated target range. As a result, in 2008 MGE paid out $183,030 in incentives for the Leak Response Time performance component. Staff allowed these performance bonuses for achieving safety goals.

3. Pension Expense

The Staff is proposing that ratemaking for MGE's pension expense continue under the method agreed to in the "Corrected Partial Non-unanimous Stipulation and Agreement as to Alternative Minimum Tax, Depreciation, Accounting for Net Cost of Removal, Accounting for Pension Expenses, Revenues, Bad Debts and May 1, 2004 Union Wage Increase Issues" (2004 Stipulation) from MGE's prior rate case, No. GR-2004-0209. In that case, the Staff proposed to change the method of calculating pension expense from the Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions (FAS 87) method to a minimum funding method designed to ensure the pension fund is adequate to meet current and future pension obligations. This method is referred to as the Employee Retirement Income Security Act of 1974 minimum (ERISA minimum) method. The provisions of Title I of ERISA, which are administered by the U.S. Department of Labor, were enacted to address public concern that funds of private pension plans were being mismanaged and abused. ERISA was the culmination of a long line of legislation concerned with the labor and tax aspects of employee benefit plans.

In the 2004 Stipulation, the parties agreed to the following provisions regarding the accounting treatment for pension expense:

> MGE's rates include a $0 annual provision for jurisdictional pension costs. The Company is authorized to reflect pension cost equal to ERISA minimum and record the difference between the ERISA minimum and the annual provision for pension cost as a regulatory asset or liability. This regulatory asset and/or liability is intended to track the difference between the provision for the ERISA minimum contribution included in cost of service in this case, and the Company's actual ERISA minimum made after the effective date of rates established in this case. This regulatory asset and /or liability will be included in rate base in the Company's next rate case and amortized over a five (5) year period. The Company is authorized to make such additional entries as are appropriate under FAS 71 to reflect that rates in this case are not based upon FAS 87 pension expense calculation. The Company is authorized to adjust its calculation of the MGE ERISA minimum, and the allocations to MGE pension-related assets and costs, to reflect the exclusion of Southern Union Company's total company actual contributions that are in excess of the ERISA minimum.

The ERISA minimum contribution has been established to determine the minimum annual level of pension contribution necessary to ensure adequate funding of pension benefits under federal law. The Staff is recommending that the ERISA minimum amount of $7,849,246 be included in rates in this case as pension expense, along with the "tracker mechanism" established in the GR-2004-0209 MGE rate case proceeding. The Staff used the $10,000,000 projected cash contribution for the 2009 plan year that is reflected in an actuarial report produced by MGE's actuary, Rudd and Wisdom, dated April 17, 2009. This amount represents Rudd and Wisdom's calculation of the minimum ERISA contribution amount for the 2009 plan year after elimination of past funding credits arising from contributions in excess of the minimum ERISA amount in recent years. The Staff believes such credits should be eliminated from the minimum ERISA calculation in order to establish a reasonable and ongoing level of pension expense for rate purposes for MGE. The Staff then applied its payroll expense allocation factor to the $10 million contribution amount to derive a pension expense amount of $7,849,246. Added to this amount is the annual amortization amount associated with the prepaid pension asset of $1,139,310 that was included in rates in MGE's Case No. GR-2004-0209. Also added is the amortization to expense related to the tracker mechanisms for pension expense in place for MGE since the 2004 rate case. The net tracker amortization amount is $2,170,777 making total pension cost to be included in this case of $11,159,333

For ratemaking purposes, a tracker mechanism is an ongoing comparison of the amount of an expense actually incurred by a utility to the amount of the same expense reflected in the utility's rates. In MGE's 2004 rate case (GR-2004-0209) proceeding, the 2004 Stipulation provided that the difference between the amount of MGE's actual pension expenses and the amount of pension expense included in its rates (both measured on a minimum ERISA basis) would be booked as a regulatory asset/liability, and amortized to expense in MGE's next rate proceeding.

While tracker mechanisms are generally not appropriate for use in setting rates, trackers for pension expenses are an exception because of the significant possible cash flow implications to utilities if their minimum ERISA pension funding requirements are materially different from their pension expense recovery levels in rates. The Staff is willing to discuss potential modifications to the existing pension tracker mechanism to reflect recent changes in financial standards and federal law regarding pension funding and accounting with MGE and other parties to this rate proceeding.

4. Other Post-Employment Benefits (OPEBs)

This adjustment annualizes OPEBs expense calculated under Financial Accounting Standard No. 106, Employers' Accounting for Postretirement Benefits Other than Pensions (FAS 106), for MGE's employees. OPEBs expense reflects MGE's current liability to provide retiree medical payments to its current employees as well as its retired employees.

The Staff used the FAS 106 cost calculation as reflected in a letter from MGE's actuary, Rudd and Wisdom, dated February 23, 2009 as the basis to determine the level of OPEBs expense to include in this case. This letter provides the level of FAS 106 OPEBs expense applicable to the fiscal year ending December 31, 2008 and as adjusted to meet Staff requirements. In conformity to the Staff's policy, this FAS 106 expense level reflects the five-year rolling average amortization of gains and losses agreed to by the Staff and MGE in MGE's prior rate case No. GR-2004-0209, and a five year amortization of accumulated fund gain/loss balances. The Staff then further adjusted the actuary's FAS 106 calculation to eliminate the detrimental impact of the Company's failure to adequately fund its FAS 106 benefit, as will be described in more detail below.

In addition, the Staff made no adjustment to MGE's $2.6 million amortization on its books of its FAS 106 Transition Benefit Obligation (TBO) amortization. This obligation or liability was assumed by MGE upon its acquisition of its Missouri gas properties from Western Resources, Inc. (WRI) in 1994. This liability of $43 million reflects MGE's liability for medical payments to retirees of the former owner of MGE's gas distribution properties, WRI. This liability is being amortized over a period of approximately 16 years and will be fully amortized in December 2012.

During the process of conducting its audit, the Staff discovered MGE was not funding its OPEBs trust funds equal to the amount of the FAS 106 calculations on which its rates have been set since at least mid-year 2003. The evidence the Staff has examined in this audit indicates that since that time MGE has not funded its OPEBs trust funds at the FAS 106 levels, but has funded the vehicles only to the extent of the monies actually due to and paid out to its retirees. The Staff believes that the provisions of Missouri Statutes, Chapter 386, Public Service Commission Section 386.315, a law passed in 1994, requires utilities that receive recovery of OPEBs expense in rates calculated on a FAS 106 accrual basis to fund the full amount of its FAS 106 rate allowance.

Once the Staff made MGE aware of its concerns regarding its OPEBs funding policy, the Company agreed in concept to fund a "catch-up" contribution to address this situation and make their customers whole for their prior FAS 106 rate contributions. The Staff has calculated what it believes to be a fair "catch-up" contribution, based upon the shortfall between the approximate $23.7 million in FAS 106 expenses collected in rates by MGE since mid-year 2003 and the approximate $9.6 million in funding MGE has made to its OPEBs trust funds since that point. The Staff's proposed "catch-up" calculation also takes into account the trust funds' lost earnings since 2003 on account of MGE's failure to fully fund these vehicles up to the FAS 106 level. The Staff's current calculation of this "catch-up" amount is $16,496,369 which should be fully the responsibility of MGE, and not its ratepayers. Because MGE was not able to provide information on the actual earned return on its OPEB trust funds going back to 2003, the Staff calculated this "catch-up" contribution assuming that MGE's assets earned an average of 7% per year on its OPEBs trust funds, which matches MGE's actuary's current assumption as a reasonable long-term expected return on OPEBs funding. The Staff would be willing to recalculate the "catch-up" contribution amount using MGE's actual earned returns going back to 2003 if this information can be made available.

Assuming agreement can be reached with the Company on appropriate funding for its OPEBs expenses, including agreement on a "catch-up" contribution, the Staff is willing to consider use of a tracker mechanism for ongoing rate treatment of MGE's FAS 106 expense. The Staff envisions that any OPEBS tracker would operate in a similar fashion to MGE's existing pension expense tracker mechanism, and other Missouri utilities also currently have OPEBs tracker mechanisms in place.

Staff Expert: Keith D. Foster

D. Other Non-Labor Expenses

1. Regulatory Expenses

a. Rate Case Expense

The Staff has included the actual costs incurred by MGE as of April 30, 2009 for this rate case (Case No. GR-2009-0355). The Staff will include additional prudently incurred rate case expenses on a going forward basis as the actual expenses are incurred by the Company. The Staff's rate case adjustment is based upon a three-year normalization of this item.

The Staff will work with the Company through the duration of this case to establish a reasonable and ongoing normalized level of rate case expense for inclusion in rates. This means any additional expenses associated with the processing of this rate filing by MGE will be examined to determine their appropriateness for inclusion in this case. This will allow costs such as consulting fees, employee travel expenditures and legal representation, which are directly associated with the length of the case through the settlement conference and hearing process, to be properly included in this rate case.

The Staff is not recommending the inclusion of prior rate case expenses in the current cost of service for this case. The Staff included an adjustment to remove $20,757 in rate case expenses for Case No. GR-2006-0422 that were booked in the test year. The Staff's policy is to recommend recovery in rates of normalized rate case expenses only on a prospective basis. The Staff believes it is inappropriate to allow specific recovery in rates of amounts related to past rate proceedings.

The Staff does not agree that rate case expense is an item that should be "amortized" in a rate case, as that implies an obligation to allow recovery of any unamortized costs in the utility's next rate proceeding.

Staff Expert: Keith D. Foster

b. PSC Assessment

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

MGE's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2010) based upon information obtained from the Commission's Budget and Fiscal Services Department.

Staff Expert: Bret G. Prenger

2. Property Tax Expense

Property taxes are those taxes assessed by state and local county taxing authorities on a utilities "real" property. Property taxes are computed using the assessed property values and property tax rates. The taxing authority, either state or local, uses an assessment date of January 1 of each year. This date is critical because it forms the basis for the property tax bill, which is generally paid at the end of that same year, no later then December 31. Utilities are required to file with the taxing authorities a valuation of its utility property based on the January 1 assessment date the first of each year. Several months later, the taxing authorities will provide the utilities with what they refer to as "assessed values" for each category of property owned. Much later in the year (typically in the late summer/fall time frame) the utilities will be given the property tax rate. Property tax bills are then issued to the utilities with "due dates" by December 31 based on the property tax rates applied to assessed values.

The adjustment proposed by the Staff in this proceeding annualizes MGE's test year booked property tax to take into account the Company's balance of taxable assets at the end of 2008 (i.e., the January 1, 2009 balance). The Staff examined the actual amounts of property tax payments made by MGE for 2001 through 2008. The Staff analyzed the relationship of actual property tax payments to the level of property at January 1 of each of these years. Staff applied the 2007 actual paid property tax rate to the plant in service balance at the end of test year period, December 31, 2008, to calculate an annualized property tax amount in this case.

In recent years, both the states of Oklahoma and Kansas have attempted to collect property taxes from gas local distribution companies (LDCs) for gas held in storage at sites physically located in those jurisdictions. MGE and other litigants have pursued appeals of these state actions in the court system to overturn the property tax assessments on stored gas. Up until the current year, MGE and other litigants have been successful in voiding the property tax payments. Recently, in Oklahoma, courts ruled against MGE and would require payment of property taxes for the storage units located in their states. In 2009, the Kansas Legislature passed a new law to allow for assessment of all gas being stored and held for resale. MGE has stated it will pursue actions in the Kansas court system to overturn the new law requiring assessment of property taxes on gas held in storage. The amount of property taxes that will be billed to MGE by taxing authorities in Kansas for gas in storage is not known with certainty at this time, and neither is whether MGE and other litigants will be successful again in overturning this legislation. Because of this uncertainty applicable to both Kansas and Oklahoma property taxes on gas in storage, the Staff has not included an amount pertaining to either jurisdiction in its case.

In Case No. GU-2010-0015, MGE has filed an application to allow it to defer on its books any property tax expenses associated with assessment of its gas in storage facilities in Kansas. The Staff has been ordered to file its recommendation in that case by September 8, 2009, following the filing of this COS Report.

Staff Expert: Bret G. Prenger

3. Bad Debt Expense

Bad debt expense is the portion of revenues that MGE is unable to collect from customers because of non-payment of customer bills. After a certain period of time has passed, delinquent customer accounts are written off and turned over to collection agencies for collection. The collection agencies and MGE are subsequently successful in collecting some portion of the delinquent amounts owed.

The Staff calculated the average annual bad debt expense for MGE by examining the actual bad debt write-offs for the last five and three years ending April 30, 2009. After analyzing the data, it was apparent there is an upward trend in this item compared to test year results and that use of the three-year average would be appropriate in this case.

The Staff's adjustment, therefore, represents the difference between a three-year average of uncollectible accounts and the test year level of bad debt expense recorded on the Company's books and records. The Staff's normalized level of bad debt expense is $9,843.535.

Staff Expert: Keith D. Foster

4. Advertising Expense

In forming its recommendation of the allowable level of advertising expense, the Staff relied on the principles the Commission set forth in Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL). In that proceeding, the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

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

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

In response to Staff data requests, MGE provided a list of all test year advertising costs with the associated description of the costs. The Staff reviewed these costs and also reviewed certain large dollar advertisement programs, such as MGE's Energy Efficiency Program. The purpose of the Staff's review of MGE's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in MGE's cost of service. For example, all costs related to safety advertising were included as well as costs necessary for MGE to communicate with its customers on utility matters, such as hours of operation or current promotions being implemented by the Company.

The Staff determined that some of the test year advertising costs were related to strictly promotional and image enhancement efforts by the Company. The Staff removed test year expenses incurred by MGE for advertising programs that are appropriately classified as institutional or image enhancement in nature. The Staff also removed advertisements related to promotional giveaways, such as logoed golf balls, etc.

All advertising costs that informed MGE's customers of ways to use energy more efficiently are included in the Staff's case.

In relation to the advertising costs discussed above for which the Staff has proposed disallowance, The Staff also removed costs incurred by MGE related to outside consultants who designed theses advertisements.

In its review of MGE's advertising expenses in this case, the Staff focused on ad campaigns, not individual ads, which is consistent with the Commission's discussion on this topic as stated in its recent rate case Report and Order, in Case No. ER-2008-0318, Ameren UE.

Staff Expert: Bret G. Prenger

5. Lobbying and MEDA Activities

This adjustment removes expenses booked by MGE in the test year that relate to any and all lobbying activities. First and foremost, the Staff believes that any costs related to the Missouri Energy Development Association (MEDA) should be booked below-the-line for ratemaking purposes and absorbed by the shareholders. The purpose of MEDA "is to develop, organize, and promote measures that will advance the ability of investor-owned utilities to build, maintain, protect, and provide the utility infrastructure and services that are critical to the health and economic well being of all Missourians." (Quotation used from the MEDA website, mission statement) MEDA is engaged in governmental affairs and lobbying activities on behalf of Missouri regulated utilities on an ongoing basis.

According to MGE, and verified by the Staff, MGE recorded all MEDA dues below-the-line, along with a majority of costs related to travel and expenses from MEDA related business trips. The Staff believes, however, that all costs associated with MEDA and all other costs related to lobbying activities by or on behalf of MGE should be booked below-the-line and excluded from the rates.

"Lobbying" is any attempt to influence the decisions of legislators. Any and all costs associated with lobbying activities of a direct and indirect nature should be excluded from a utility's cost of service and be absorbed by the shareholders. The Staff follows the belief that both payroll and non-payroll charges related to lobbying should be excluded. Ideally, the utility should record all time spent on "lobbying" activities on an employees timesheet. However, MGE's officers do not and have not specifically tracked time spent on lobbying related activities on their timesheets. In Case No. GR-2004-0209, in the absence of detailed tracking of time spent on lobbying activity by certain of MGE's officer, the Commission ruled that a reasonable percentage of payroll expense for officers known to have engaged in lobbying activity should be disallowed and treated below-the-line for rate purposes.

Based on this precedent, the Staff made percentage removals from all employees' salaries known to have been involved in lobbying related activity. In this rate case, the three employees are Mr. Robert Hack, the Chief Operating Officer; Mr. Mike Noack, Director of Regulatory Affairs; and Ms. Pamela Levetzow, the Director of the Customer and Governmental Relations Department. Based upon responses to Staff data requests, all three of these employees participated in MEDA activities in the test year. Further, both Mr. Noack and Ms. Levetzow testified before the Missouri Legislature in its 2008 session in support of efforts to allow collection of certain bad debt expenses on a single-issue basis through the purchased gas adjustment mechanism. Ms. Levetzow also has the responsibility for managing and coordinating the activities of MGE's hired outside lobbying firms. Similar to the situation experienced in MGE's 2004 rate case, none of these MGE employees kept track of their time spent on lobbying related activities in sufficient detail to allow for determination of a reasonably exact percentage of their time and payroll expense tied to lobbying efforts. Based on examination and the precedents established in prior MGE rate cases, the Staff recommends that adjustments removing 10 percent of salary for Mr. Hack's and Mr. Noack's salary are appropriate. For Mrs. Levetzow, who appears to have additional lobbying related responsibilities than Mr. Hack and Mr. Noack, the Staff recommends that a 20 percent disallowance be applied to her salary.

In prior cases, the Commission disallowed a portion of the labor costs of the Customer and Governmental Relations (CGR) Department on the basis that the employees within this MGE Department devoted a portion of their time to lobbying related activities, community relations activities and charitable campaigns. In the last several MGE rate cases, CGR employees maintained timesheets that allowed for a tracking of these types of below-the-line activities. In this audit, the Staff determined that the CGR Department employees no longer were keeping timesheets that contained this kind of tracking. MGE explained that this change was due to the fact that the lobbying, community relations and charitable activities engaged in by this Department and disallowed by the Commission are no longer part of the job duties of any CGR Department employees except for Ms. Levetzow, the Department's Manager. The Staff will continue to monitor the activities of the CGR Department respecting their possible involvement in below-the-line activities in future rate proceedings.

Staff Expert: Bret G. Prenger

6. Medical and Dental Expenses

MGE currently offers its employees medical, dental, and vision insurance benefits through a combination of MGE and employee contributions. Employee contributions to the benefit plans began in January 2008. The Staff reviewed the actual claims paid balance of medical, dental, and vision expenses incurred by MGE (less employee contributions) for a five-year period ending with the update period, April 2009. The Staff analysis shows that healthcare expenses have tended to increase slightly from year-to-year at MGE, even with the initiation of employee contributions in 2008. The Staff used the actual book expense of employee healthcare plans in effect through the update period for the twelve months ending April 30, 2009. This amount was compared to the test year level to determine the adjustment.

Staff Expert: Keith D. Foster

7. Franchise Taxes

The Staff has adjusted MGE's test year franchise tax expense by excluding Southern Union's goodwill assets from the calculation. Goodwill, or acquisition adjustments, are not considered for ratemaking treatment purposes in Missouri.

Staff Expert: Keith D. Foster

8. Injuries and Damages

Injuries and damages expense represents the portion of legal claims against a utility that is not subject to reimbursement under the utility's insurance policies. Injuries and damages expense normally consists of the following components:

- General Liability
- Auto Liability
- Workers Compensation

General liability claims tend to be the largest component of injuries and damages expense, and the part that can give rise to the most controversy in rate proceedings.

Generally accepted accounting principles (GAAP) normally require companies to book injuries and damages claims on an accrual basis. This means the expense is based upon estimated future claims payout amounts, rather than the actual cash payments made. However, for ratemaking purposes, the Staff believes injuries and damages expense should be measured on a "cash" basis; i.e., be based upon actual cash payouts by the utility for claims made against it. This approach necessitates that the accrued book expense for injuries and damages be adjusted to a cash basis.

The Company normalized its injuries and damages by taking a three-year average .of workmen's compensation, auto and general liability claims paid and adding that average to the insurance premiums paid during the test year.

As discussed above, the Staff used the cash basis methodology to calculate their injury and damages adjustment. We calculated a three-year average of payouts in account 925 (Injuries and Damages), and following precedent in prior MGE cases, Staff used that average to determine its normalized number. The Staff multiplied the average by the Staff's payroll expense percentage to obtain only the expense portion of the adjustment. The result was then subtracted from the Company's net payments in account 925, resulting in the adjustment amount.

Staff Expert: Bret G. Prenger

9. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of its customers) associated with unanticipated losses.

Insurance normally consists of the following types of coverage:

- Directors and Officers Liability Insurance
- Boiler & Machinery - covers boilers and business interruptions.
- Workers' Compensation - covers all employees.
- General Liability – all general liability claims against the company.
- Property
- Contractors' Equipment – leased equipment.

- Combination Crime – general theft and forgery by employees, plus kidnapping, ransom and extortion.
- Fiduciary and Employee Benefit Liability
- Excess Liability – all general liability claims against the company

As an ongoing and normal expense of a utility, insurance expense should be analyzed in every rate case audit to determine whether normalization/annualization of the test year expense is appropriate.

Premiums for insurance are normally pre-paid by utilities (i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect). Most insurance policies cover a semi-annual (six-month) period. Therefore, insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense over the life of the policy. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates. The Company's prepayments included in its rate base are discussed separately in this COS Report.

The Staff adjustment annualizes MGE's test year insurance expense to reflect the premiums in effect at April 30, 2009 to reflect the ongoing and normal expense for this item to MGE. The two adjustments were made to account 924 (property insurance) and account 925 (other premiums, including: worker's comp, auto and general liability).

Staff Expert: Bret G. Prenger

<u>10. Postage Expenses</u>

Most utilities incur substantial postage expense as their monthly customer billings are sent by mail. The Staff made adjustment to MGE'S test year postage expense to reflect the increase to postal rates which became effective in 2008 and 2009.

To calculate its adjustment, Staff obtained from the Company the number of mailings that it sent out in 2008. The Staff then determined the average increase applicable to the items mailed from the calendar year 2008 test year incorporating the current rates charged by the U.S. Postal Service for postage, which we calculated to be $.014 per item mailed. To complete the adjustment, the Staff then multiplied the number of the 2008 total mailed items by $.014 to derive the incremental adjustment of $104,736.04 to postage expense for the May 11, 2009 postage increase.

Staff Expert: Bret G. Prenger

11. Dues and Donations

Dues and donations are expenditures made by utilities to organizations, clubs, charitable funds and other groups. Dues can be defined as the amount paid to an organization, by the utility, to allow the utility or individuals employed by the utility company to participate in and benefit from the organization's activities. Donations are defined as discretionary amounts paid to individuals or organizations for charitable reasons, with no direct business benefit.

The Staff made adjustments to disallow certain amounts of the Company's dues and donations test year expenses in the amount of $138,186. Examples of dues excluded from the case are dues paid to the Rotary Club, The Optimist Club of St. Joseph, MEDA, and the Chamber of Commerce-Missouri etc.

Consistent with the Commission's decision in Case No. GR-77-33, Laclede Gas Company, the Staff excluded these dues and donations from the cost of service because they: 1) are not necessary for the provision of safe and adequate service, 2) do not provide any direct benefit to ratepayers, and 3) including such expenditures in rates places the ratepayer in the position of being an involuntary donor to the organization in question.

Staff Expert: Bret G. Prenger

12. Environmental Costs

MGE is subject to environmental remediation costs imposed upon it due to federal and state statutory and regulatory requirements. Some of these costs are associated with items such as mercury contamination and asbestos clean-up efforts, but the vast majority of the Company's environmental costs relate to manufactured gas plant (MGP) remediation costs. In the test year, MGE incurred a total of $6,764,300 in environmental costs, of which $6,695,238 was due to MGP clean-up efforts. It is the Staff's understanding that the work in the test year was performed under the oversight of federal and state environmental regulators. In this case, MGE is seeking rate recovery of its test year environmental expenses, net of insurance recoveries, in an amount in excess of $5 million.

Manufactured gas plants were facilities owned by companies from the 19th century to the early-to-mid 20th century. Years after the plants ceased operation, they were found to have left residues of pollutants in the ground. The 1980 Comprehensive Environmental Compensation and Liability Act (also known as the Superfund Act), as amended in 1986, imposed strict, joint and several liabilities on present or former owners or operators of facilities where substances have been or are threatened to be released into the environment, including MGP sites. MGE is the present owner of a number of MGP sites, and thus is potentially liable for at least a portion of any clean-up costs required by the Environmental Protection Agency or other regulatory bodies relating to these sites. Clean-up activities have occurred at several sites owned by MGE in past years, in the test year and continuing into 2009.

The Staff generally supports inclusion in rates of environmental remediation costs imposed upon utilities by law or regulation, except in cases of negligence or imprudence. Rate recovery of MGE's MGP costs, though, is complicated by several factors. First, a portion of MGE's environmental expenditures have been reimbursed through insurance claims (approximately $1.5 million in the test year), and some part of MGE's current and future environmental payouts may be similarly subject to reimbursement. Second, Western Resources, Inc. (WRI), the former owner of MGE's Missouri gas properties, may be required to reimburse a portion of MGE's environmental expenses under the Environmental Liability Agreement (ELA) signed by MGE and WRI in 1994. Third, in the 15 years, MGE has owned its Missouri property, the amount of environmental costs experienced has varied widely from year to year.

MGE has received almost $10 million in insurance recoveries for environmental remediation costs since 2001, including approximately $1.5 million in the test year.

In general terms, the ELA states that MGE may seek recovery from WRI of a portion of certain qualifying environmental expenditures (including MGP clean-up costs) incurred between February 1994 and January 2009, if such costs are not recoverable from MGE's insurance carriers, or from other "potentially responsible parties (PRPs), or from MGE's customers in rates. If those conditions were met, under the ELA MGE would still be responsible for the first $3 million in qualifying environmental remediation expenditures during the 15-year duration of the ELA, but WRI would then be liable for 50% of the next $15 million in incurred expenses. ** ____

____

____

____

____

____

_______________ **

The approximate $6.7 million spent by MGE in the test year for environmental costs is the highest annual level experienced in its history. (MGE incurred $6.4 million in environmental costs in 2003, but the third highest annual total for this item was only $930,000 in 2002.) Based upon this history, the Staff believes that the test year level of environmental expenses for MGE is not indicative of a reasonable ongoing cost level for this item. Further, not only should this expense be normalized for rate purposes, but some recognition of MGE's past history of insurance reimbursements should also be reflected in the adjustment, ** **

For these reasons, the Staff recommends that a three year average (calendar year 2006-2008) of MGE environmental remediation costs ($2.546 million) be netted against a three-year average of environmental insurance recoveries ($663,000) to calculate a normalized net expense amount of $1.883 million. ** ** The Staff believes that it is appropriate for MGE to attempt to maximize recovery of environmental costs from insurance carriers, other potentially responsible third parties and WRI prior to seeking rate recovery of these costs from its customers. Therefore, the Staff recommends that MGE's rate

NP

recovery in this case for environmental remediation costs be limited to no more than $941,500 (half of $1,883,000).

Staff Expert: Mark L. Oligschlaeger

<u>13. Payment of Customer Credit Card Surcharge by MGE</u>

In its current rate application, MGE is seeking authorization from the Commission to have credit card companies transfer a surcharge of $3.50 currently paid by customers using their credit card to pay their MGE gas bill, so that MGE will then be responsible for paying this surcharge. MGE has reported a decline in the use of credit card payments due to the charge individual customers incur for paying their MGE bills via credit card. The benefit of customers using credit cards to pay their MGE bill is that if the customer defaults on the credit card bill, the credit card company assumes the liability for the default. A reduction in the use of credit cards to pay their MGE bills may result in increased uncollectable expenses being experienced by MGE. It is very possible residential rate payers will eventually be harmed by the decline in credit card use to pay MGE bills through being charged higher rates on account of increased uncollectable expenses.

In addition to transferring uncollectible liability from MGE to the credit card companies through the payment of gas bills on credit cards, there is other benefit in this practice. Using a credit card is likely to make bill payment easier for some customers. Paying via the internet is a convenience to the customers. Use of credit card gives the customer a chance to avoid disconnect, thereby, saving MGE the cost of a trip to collect or disconnect, and a subsequent trip to re-establish service. There are potential benefits to both customers and MGE that could occur by customers continuing to use, or by expanding the use of credit cards to pay MGE bills. These benefits may take place beyond the potential reduction to uncollectable an expense, which is the primary, potential benefit. Encouraging use of a credit card should minimize potential defaults in the future. At least, MGE absorbing the cost of using a credit card should help stem the reduction in credit-card usage that is occurring today.

MGE seeks to include $800,982 of annual expense in its revenue requirement due to MGE assuming responsibility to credit card surcharges and passing along the associated costs to its general body of ratepayers. Staff agrees that this amount should be included in expense, and it is reflected in Adjustment E-78.7

Kansas City Power & Light Company is presently also paying the customer's surcharge for credit cards, similar to what MGE is proposing in this case. KCPL's cost of assuming these payments is also currently reflected in its customer rates. Therefore, MGE would not be the first to adopt this policy.

Staff Expert: Michael Ensrud

14. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, information technology and other services to MGE on an as needed basis in order to assist the Company in carrying out its operational activities. The Staff reviewed MGE's test year outside services expense booked to Accounts 92300003 and 92300007. The Staff analyzed the amounts paid for outside services from 2006 through 2008 and believes the amount of outside service expenses incurred in test year is representative of an ongoing level of incurred costs for these accounts (with the exception of environmental remediation services, which are discussed in Section VIII.D.12 of this Report). The Staff did disallow however certain costs where the Company could not provide proper documentation for some of these outside services.

** ____

____ **

Staff Expert: Amanda C. McMellen

15. Rents

The Company rents the parking lot adjacent to and behind its main headquarters in Kansas City, MO. The Company receives revenue from certain individuals who pay for the use of this parking lot. The Staff removed from this case the annual parking lot revenue received in order to offset the rent paid by the Company. Similarly, the Company leases its building and subsequently subleases some space in that building to other entities. The Company also pays taxes, maintenance, utility and office supplies for this building. The Staff offset the Company's building expenses from the earnings that the Company received from its subleases.

Staff Expert: Amanda C. McMellen

16. Leases

The Company formerly leased certain vehicles used in its utility operations. Due to conditions beyond the Company's control, these leases were terminated in November 2008. The lessor has allowed MGE to phase the buyout of these vehicles over a three (3) month period of time (April, May and June 2009). The Staff has included the plant and depreciation reserve for the vehicles purchased under this program through April 30, 2009, the end of the update period in this case. The Staff has not included any amount for the buyouts which were to take place in May and June of 2009. Those additional buyouts beyond April 2009 will be reviewed in the true-up in this case.

Staff Expert: Amanda C. McMellen

17. Weatherization and Conservation Programs

MGE currently participates in a low-income weatherization program and a natural gas conservation program. The low-income weatherization program is designed to assist customers in reducing their energy costs and possibly the Company's Bad Debt expense. The natural gas conservation program is intended to educate customers regarding energy efficiency and promote installation of high-efficiency gas appliances and is designed to promote the energy efficiency among MGE's customers. These programs offer incentives to MGE's customers to become more energy conscious. In the last MGE rate case, both the weatherization and conservation programs were awarded annual funding levels of $750,000 each. The Company has not proposed an increase in the funding of these programs in this proceeding. The Staff agrees with the Company concerning program funding levels and has not proposed adjustments to MGE's test year expenditures in this case.

Staff Expert: Amanda C. McMellen

18. Transportation and Work Equipment Clearing

Clearing accounts are accounts used to accumulate costs that will later be moved to operating and capital accounts. This clearing account accumulates costs associated with transportation (vehicles) and major work equipment. These costs include payroll, benefits, insurance, taxes, depreciation and costs associated with maintaining the vehicles and equipment. The Staff has made adjustments to include in the clearing accounts amounts associated with the change in depreciation expense related to purchase of formerly leased vehicles through April 30, 2009, the end of the update period. These costs are subject to the O&M factor and then distributed to appropriate accounts based on the Staff's current payroll distribution factors.

Staff Expert: Amanda C. McMellen

19. Amortization Expense

Amortization expense is similar in concept to depreciation expense, but pertains to intangible assets. Amortization expense is usually applied to assets such as leasehold improvements and cost deferrals. Because of the intangible nature of the assets involved, the amortization period is not tied to a estimated asset life but is instead established for a reasonable period of time; i.e., five, ten or twenty years.

The Staff's adjustment annualizes the Company's amortization expense based on levels updated through April 30, 2009, the update period. Included in this adjustment are amounts for the amortization of deferrals of previously approved amortizations for the Infinium Software, SLRP and Net Cost of Removal. The Company is not seeking recovery in this case of an Emergency Cold Weather Rule amortization booked in the test year, but that will expire after the end of the test year and update period. The Staff likewise did not include this amortization in the case.

Staff Expert: Amanda C. McMellen

20. Miscellaneous Expenses

Miscellaneous expenses are costs associated with items such as retirement meals, retirement cakes, luncheons, company sponsored parties, etc. These costs provide no benefit to the ratepayers and are excluded because they are not necessary to the provision of service.

Staff Expert: Amanda C. McMellen

E. Current and Deferred Income Tax Expense

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

Current income tax has been calculated generally consistent with the methodology used in MGE's most recent rate case, Case No. GR-2006-0422. A "tax timing difference" occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from the timing required by the Internal Revenue Service (IRS) in determining taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

Subtractions from Operating Income:

Interest Expense – Weighted Cost of Debt times Rate Base

Tax Depreciation

For most utilities, it is necessary to break out a utility's tax depreciation into two separate components: tax straight-line depreciation and excess tax depreciation. Excess tax depreciation differs from straight-line book depreciation due to the higher depreciation rates allowed in the early years of an asset's life under the current tax code. Tax straight-line depreciation is different from book straight-line depreciation due to the different tax basis of property allowed under the tax code. Most tax basis differences were eliminated for assets placed into service after 1986 due to the Tax Reform Act enacted that year. Because MGE purchased its Missouri properties after the passage of the Tax Reform Act, the differences between its tax and book basis for its depreciable property are immaterial, and the Staff has taken the approach of only using one tax depreciation amount in its income tax accounting schedule.

In accordance with its normal practice and the provisions of the tax code, the Staff is proposing full normalization of the book/tax depreciation rate difference in its filing. Consistent with normalization treatment, the Staff has set its book and tax depreciation amount equal in Accounting Schedule 11, Income Tax. This treatment means that all of the income tax expense calculated on Accounting Schedule 11 is current income tax, and none is deferred income tax. The alternative approach of presenting two different amounts for book and tax depreciation in the Staff's income tax calculation would have led to the same total amount of income tax expense to be included in the Staff's case, but some of that expense would have been denoted as deferred tax expense. For simplicity of presentation, the Staff did not choose that income tax presentation approach.

Consistent with the Staff's treatment in MGE's last rate case, Case No. GR-2006-0422, the Staff is treating the portion of the Company's taxes attributable to the Kansas City earnings tax by including a four-year average of the actual tax liability as an adjustment to operating expense. This is done instead of incorporating the Kansas City earnings tax in the composite effective tax rate along with federal and state income taxes. As Staff discussed in MGE's prior rate cases, MGE's Kansas City, MO earnings tax apportionment calculation is derived from its parent company Southern Union's annual gross receipts, instead of MGE's stand-alone earnings. In response to Staff Data Request No.79.6, the amount of the Kansas City earnings tax in recent years varied dependant upon the fluctuation of the gross receipts earned by Southern Union. The Staff believes this tax is best treated for rate purposes by using a normalized level in expense. The Staff used a four-year average of actual KC earnings tax liability from 2004 to 2007 in this case.

Staff Expert: Keith D. Foster

Appendices:

Appendix 1: Staff Credentials
Appendix 2: Support for Staff Cost of Capital Recommendations – David Murray
Appendix 3: Summary of Rate Revenue – Amanda C. McMellen
Appendix 4: Summary of Heating Degree Days – Manisha Lakhanpal /Henry Warren
Appendix 5: Summary of Staff Adjustments to Sales – Amanda Mc Mellen
Appendix 6: Staff Recommended Depreciation Rates – Rosella L. Schad

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF MICHAEL J. ENSRUD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael J. Ensrud, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 111 and 112; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael J. Ensrud

Michael J. Ensrud

Subscribed and sworn to before me this 20th day of August, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF KEITH D. FOSTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith D. Foster, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 56-59, 61-62, 87-96, 98-99, 103-104, 116-118 and that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith D. Foster

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF KAREN HERRINGTON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Herrington, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 44-55; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Karen Herrington

Karen Herrington

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 69-73; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Manisha Lakhanpal

Manisha Lakhanpal

Subscribed and sworn to before me this 20th day of August, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Amanda C. McMellen, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 55-56, 59-61, 67-71, 77-80, 82-84, 112-116; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Amanda C McMellen

Amanda C. McMellen

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 6-42; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Mark L. Oligschlaeger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 108-111; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Mark L. Oligschlaeger

Mark L. Oligschlaeger

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF BRET G. PRENGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Bret G. Prenger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 43-44, 96-98, 99-109 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Bret G. Prenger

Bret G. Prenger

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF ANNE E. ROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Anne E. Ross, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 80-82 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Anne E Ross

Anne E. Ross

Subscribed and sworn to before me this 20th day of August, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	))))	Case No. GR-2009-0355

AFFIDAVIT OF ROSELLA L. SCHAD, PE, CPA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 84-87; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Rosella L. Schad
Rosella L. Schad

Subscribed and sworn to before me this 21st day of August, 2009.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Tariff Sheets Designed to Increase Rates for Gas Service in the Company's Missouri Service Area.	)))))	Case No. GR-2009-0355

AFFIDAVIT OF HENRY E. WARREN, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Henry E. Warren, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 73-77 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E. Warren
Henry E. Warren, PhD

Subscribed and sworn to before me this 20th day of August, 2009.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer
Notary Public